Southwest Power Pool

Cost-Benefit Analysis

Performed for the SPP Regional State Committee

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Charles River Associates

Charles River Associates

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List of Abbreviations

AECC	Arkansas Electric Cooperative Corporation
AEP	American Electric Power
ATC	Available Transfer Capability
CAO	Control Area Operator
CBA	Cost-Benefit analysis
CBTF	SPP-RSC Cost-Benefit Task Force
CC	Combined Cycle
CRA	Charles River Associates
CT	Combustion Turbine
EC	Electric Cooperative
EIS	Energy Imbalance Service
FERC	Federal Energy Regulatory Commission
GRDA	Grand River Dam Authority
INDN	City Power & Light, Independence
IOU	Investor-Owned Utility
IPP	Independent Power Producer
ISO	Independent System Operator
IT	Information Technology
KACY	The Board of Public Utilities, Kansas, City
KCPL	Kansas City Power & Light
LIP	Locational Imbalance Pricing
LMP	Locational Marginal Price; Locational Marginal Pricing
MAPS	Multi-Area Production Simulation
MIPU	Missouri Public Service and St. Joseph Light & Power
MISO	Midwest ISO
MW	Megawatt
MWh	Megawatt-Hour
OATTs	Open Access Transmission Tariffs
OGE	Oklahoma Gas & Electric
O&M	Operation and Maintenance
OMPA	Oklahoma Municipal Power Authority
RSC	Regional State Committee
RDI	Resource Data International
RMR	Reliability Must Run
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SPC	SPP Strategic Planning Committee
SPP	Southwest Power Pool
SPS	Southwest Public Service
SWPA	Southwestern Power Administration
TLR	Transmission Line Relief
TTC	Total Transfer Capability
VOM	Variable Operation and Maintenance
WEPL	WestPlains Energy

Executive Summary

Background

Charles River Associates (CRA) has conducted a cost-benefit analysis for the members[1] of the Southwest Power Pool (SPP) under contract with the SPP Regional State Committee (RSC)[2]. The study was requested to assess the impact of alternative future roles of SPP in light of its approval as a Regional Transmission Organization (RTO) by the Federal Energy Regulatory Commission (FERC). The study involved (1) an analysis of the probable costs and benefits that would accrue from consolidated services and functions (which include reliability coordination and regional tariff administration) and (2) the costs and benefits of SPP's implementation of an Energy Imbalance Service (EIS) market.

The RSC established a Cost Benefit Task Force (CBTF) composed of staff members from the member state commissions, SPP member utilities, one consumer advocate, and SPP staff members to initiate and coordinate this project. The RSC through the CBTF requested that CRA assess the costs and benefits of two alternative cases, in particular. The impact of SPP implementing an EIS market is evaluated in the EIS case, while the impact of individual transmission owners providing transmission service under their own Open Access Transmission Tariffs (OATTs or Tariffs) is evaluated in the Stand-Alone case. The EIS case is intended to represent an incremental step in the direction of Locational Marginal Pricing (LMP), while the Stand-Alone case is intended to represent a return to the traditional approach of individual control areas entering into bilateral trading arrangements and control of transmission congestion through NERC Transmission Line Relief (TLR) procedures.

Methodology

CRA approached the study of these two scenarios through five areas of analysis:

a) Wholesale Energy Modeling
b) Allocation of Energy Market Impacts and Cost Impacts
c) Qualitative Assessment of Energy Imbalance Impacts
d) Qualitative Assessment of Market Power Impacts
e) Aquila Sensitivity Cases

The time horizon for the study consisted of the calendar years 2006–2015. Detailed simulations were performed for 2006, 2010, and 2014, and interpolation and extrapolation were used to obtain results for the other years in the study horizon. The Aquila Sensitivity cases were evaluated for the model year 2006 only.

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[1] The Southwestern Power Administration has formally withdrawn from the SPP, but will continue to participate in SPP through a contractual arrangement. In this study, the Southwestern Power Administration was treated as a full-member of SPP.
[2] The SPP RSC is a voluntary organization that may consist of one designated commissioner from each state regulatory commission with jurisdiction over one or more SPP members.

The **Wholesale Energy Modeling** addressed the expected impacts on the SPP energy market resulting from the different operational or system configuration assumptions in the various cases. This energy market simulation, using General Electric's MAPS tool, included an assessment of the impact on production costs, on the dispatch of the system, and on the interregional flows in the study area.

The system production costs associated with each market design alternative were the primary measure used for the quantitative evaluation of the scenarios. The energy modeling results also served as inputs to the allocation processes for further evaluation of impacts.

CRA modeled three operational market scenarios in this study:

- **Base case:** SPP within its current footprint with no balancing market
- **EIS case:** A real-time Energy Imbalance Service market is implemented within today's SPP tariff footprint
- **Stand-Alone case:** SPP tariff is abandoned and each transmission operator operates under its own transmission tariff

The quantitative modeling of these three scenarios was distinguished by three factors: through-and-out rates for transmission service, the dispatch of non-network generating units, and the transfer limits on constraints within SPP. Through-and-out rates are currently not used within the SPP footprint and so are not in place in either the Base case or the EIS case. These internal SPP transmission rates are implemented only in the Stand-Alone case**.** The non-network generating units, primarily certain merchants units in SPP, are considered to be restricted in their dispatch in the Base and Stand-Alone cases due to a higher priority dispatch accorded to network resources on behalf of native load. In the Base case, transfer limits were set below the physical capacity of the associated lines to reflect suboptimal congestion management through the TLR process, consistent with observed historical utilization. Both the restriction of the non-network resources and the suboptimal transfer capacities are eliminated in the EIS case, thereby enabling the merchant plants to participate fully in the EIS market and resulting in more efficient congestion management.

The **Allocation of Energy Market Impacts and Cost Impacts** is the portion of the cost-benefit study that provides an assessment of the cost and energy market impacts on individual market participants. This assessment was based on specific assumptions regarding regulatory policies and the sharing of trade benefits and was used to provide detailed company- and state-specific impact measures. The major categories of benefits and costs were trade benefits, wheeling charges and revenues, SPP implementation and operating costs, and individual utility implementation and operating costs.

The **Qualitative Assessment of Energy Imbalance Impacts** addresses impacts of Energy Imbalance Service other than those quantified in the modeling. As part of this qualitative analysis, CRA consultants compared a number of characteristics of the markets being assessed (e.g., the real-time energy pricing policies or transmission right product design) against a variety of metrics such as volatility, risk, and competition.

The **Qualitative Assessment of Market Power Impacts** addresses the likelihood that the implementation of an EIS in SPP would increase the potential for the exercise of market power in the SPP region, especially in the context of the market monitoring function and the continuation of cost-based regulation in this region.

The **Aquila Sensitivity Cases** portion of the study addresses the impact if Aquila were considered to be part of SPP rather than part of the MISO RTO, which was the assumption for the balance of the study. In this case the reserve requirements for individual SPP companies are reduced as reserve sharing is implemented over a larger set of participants (including the Aquila regions). The SPP regional wholesale energy modeling results were determined, as were wholesale impacts on Aquila. The Aquila sensitivity study was performed for the Base case and for the EIS case.

Findings

EIS Case

The study found that the implementation of an EIS market within SPP would provide optimal aggregate trade benefits of $614 million over the 10-year study period[3] to the transmission owners under the SPP tariff,[4] as summarized in Table 1. These trade benefits are the allocated portion of the overall production cost savings that occur within the entire modeling footprint (most of the Eastern Interconnection), as determined by the MAPS simulation study. This represents about 2.5% of the total production costs (production costs include fuel, variable O&M, start-up, and emissions costs) within the SPP area during this period. The study accounted for impacts due to changes in wheeling charges and wheeling revenues, which was a minor consideration as shown in Table 1.

The study also evaluated the administrative costs of implementing the EIS market, both in terms of the costs incurred by SPP to administer the EIS market and of the costs to the utilities of participating in such a market. SPP's 10-year costs are shown in Table 1 as being $105 million, while the 10-year costs of the EIS market participants are estimated to be $108 million. On net, the EIS market is estimated to provide considerably more benefits than costs, with the net benefits being $373 million to the transmission owners under the SPP tariff over the 10-year study period. In addition, the study estimated that benefits to other typical load-serving entities in the EIS market would be an additional $45.2 million without consideration of individual implementation costs.[5]

[3] All study period figures in this study are discounted present values as of January 1, 2006 over the 2006-2015 period. An annual discount rate of 10% was applied. Annual inflation was assumed to be 2.3% over the study period.

[4] Transmission owners under the SPP tariff include six investor-owned utilities (American Electric Power, Empire Electric Company, Kansas City Power & Light, Oklahoma Gas & Electric, Southwestern Public Service, and Westar Energy), two cooperatives (Midwest Energy and Western Farmers), one federal agency (Southwestern Power Administration), one state agency (Grand River Dam Authority) and one municipality (Springfield, Missouri). The Southwestern Power Administration has recently indicated that it will formally withdraw from the SPP, but continue to participate in SPP through a contractual arrangement. In this study, the Southwestern Power Administration was treated as a full-member of SPP.

[5] These other entities are Arkansas Electric Cooperative Corporation; Oklahoma Municipal Power Authority; the Board of Public Utilities, Kansas City, Kansas; and City Power and Light, Independence, Missouri. Together with the transmission owners under the SPP tariff, these entities account for nearly all non-merchant generation in the EIS market. Other SPP members not modeled as participating in the EIS market in these results include Aquila, Cleco Power, Sunflower Electric, City of Lafayette, Louisiana, and Louisiana Energy & Power Authority. The introduction of the EIS market affects these utilities as well, and the impacts are reported in the body of this study.

Table 1 EIS Case, Benefits (Costs) by Category for Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	614.3
Transmission Wheeling Charges	24.4
Transmission Wheeling Revenues	(53.2)
SPP EIS Implementation Costs	(104.8)
Participant EIS Implementation Costs	(107.6)
Total	373.1

Table 2 shows how these SPP-wide net benefits are estimated to be distributed among the individual utilities within SPP. Most of the utilities are shown as having positive net benefits over the 10-year study period. Four of the utilities (KCPL, Westar Energy, Midwest Energy, SWPA, and GRDA) have small impacts, either positive or negative, that should be interpreted as essentially breaking even. The results for these utilities are probably smaller than the margin of error of this study.[6] Those utilities with larger positive impacts tend to have a relatively significant impact on the dispatch of their generating units under the institution of an EIS market.

[6] The study results are subject to a margin of error due to various abstractions that must be made in any modeling exercise such as this. Possible sources of error include incomplete monitoring of transmission constraints, incomplete data on generation characteristics, fuel price forecast margin of error, and error in forecasting RTO costs. CRA has not had the opportunity to develop a formal margin of error for this study, but CRA experience in modeling exercises of this type suggest that changes of less than $10 million over the study period for individual companies are likely to be within the study's margin of error.

Table 2 EIS Case, Benefits (Costs) for Individual Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefit
AEP	IOU	58.5
Empire	IOU	70.0
KCPL	IOU	(2.2)
OGE	IOU	95.3
SPS	IOU	69.4
Westar Energy	IOU	5.3
Midwest Energy	Coop	(0.7)
Western Farmers	Coop	75.2
SWPA	Fed	1.2
GRDA	State	(5.0)
Springfield, MO	Muni	6.0
Total		373.1

Table 3 shows how the results for the retail customers of the six investor-owned utilities (IOUs) in Table 2 are estimated to be distributed among the states in the region. This state-by-state allocation of benefits is based on a load-ratio share methodology[7] and shows that the IOU retail customers in all states but Louisiana would most likely experience positive benefits, although the positive results for Arkansas, Kansas, and New Mexico are relatively modest.[8]

Table 3 EIS Market Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Arkansas	9.2
Louisiana	(3.8)
Kansas	8.3
Missouri	60.0
New Mexico	9.2
Oklahoma	141.7
Texas	26.6

[7] Trade benefits for AEP were allocated to the AEP operating companies, Public Service Company of Oklahoma and Southwestern Electric Power Company, before allocation to individual states.

[8] To the extent that agreements are in place that share costs between IOU operating companies, these considerations were not taken into account in this study.

Stand-Alone Case

In the Stand-Alone case, implementation of intra-SPP wheeling rates leads to a less efficient dispatch and thereby increases system-wide production costs in comparison with the Base case. Table 4 shows that the trade benefits allocated to the transmission owners under the SPP tariff area is negative $21 million over the 10-year study period. This is about 0.1% of the production costs in this area over this period. By itself, this $21 million in additional costs is not a major consideration and could be interpreted to be a break-even result for the region as a whole. Other factors must be considered, however. Wheeling rate impacts are shown in Table 4 as being somewhat positive (the net of the wheeling revenue and wheeling charge impacts is about a positive $16 million). CRA has some concern that loop-flow impacts that cannot be estimated directly using the MAPS simulation model may influence this wheeling rate impact, so this somewhat small impact is considered to be a break-even result.

The major costs associated with this case are the administrative costs that must be undertaken by the individual utilities if SPP were to no longer administer the SPP Tariff. These are reported in Table 4 as being about negative $46 million, meaning that the "benefit" is negative (an increased cost is reported in the table as a negative benefit so that all of the numbers in the table can be added directly instead of adding benefits and subtracting costs). In addition, the SPP withdrawal obligations are shown as an additional cost of $47 million.

These additional costs are offset to some degree by the reduction in FERC fees that would occur under a Stand-Alone scenario, assuming that FERC continues to assess its fees as it does at present. Because 100 percent of load is used by FERC to assess its fees for RTOs, but only wholesale load is used for stand-alone utilities, an appearance is created that a substantial saving in FERC fees would result if the utilities were to revert to a stand-alone status. CRA cannot assess the reasonableness of this estimate, which would appear to be subject to substantial regulatory risk. That is, this impact could effectively be eliminated by a simple change in FERC's assessment approach. CRA has no way to assess whether such a revision in FERC's assessment formula is likely, but we note that this impact is of a purely pecuniary character, as opposed to the real resource costs and benefits measured elsewhere in this study. While such pecuniary impacts are important, they are subject to considerably more uncertainty. So, while Table 4 indicates that the Stand-Alone case would result in about $70 million of additional net costs over the 10-year study period (i.e., a negative $70 million of net benefits), this estimate could easily be closer to $100 million in net costs if FERC were to revise the formula for its fees.

Table 4 Stand-Alone Case, Benefits (Costs) by Category for Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	(20.9)
Transmission Wheeling Charges	(499.8)
Transmission Wheeling Revenues	515.6
Costs to Provide SPP Functions	(46.0)
FERC Charges	27.3
Transmission Construction Costs	0.5
Withdrawal Obligations	(47.2)
Total	(70.5)

Table 5 shows how the net costs (negative net benefits) are allocated to individual utilities within SPP. The results in Table 5 are shown with and without the impact of wheeling revenues and charges. As shown, excluding these wheeling impacts, the benefits of moving to Stand-Alone status for each individual transmission owner is either close to zero or somewhat negative (i.e., an increase in costs).

While the aggregate benefit for the transmission owners under the SPP tariff in Table 5 is negative, Kansas City Power & Light and Southwestern Public Service show a moderately positive benefit when wheeling impacts are included. For these companies, the positive result is driven by a significant increase in the wheeling revenues calculated using MAPS tie-line flows when through-and-out wheeling charges to other SPP companies are instituted in the Stand-Alone case. In practice, the increase in wheeling revenues would be associated with a utility that exports significant amounts of power to other SPP companies. Since there are no intra-SPP wheeling charges in the Base case, utilities that export significant amounts of power to other SPP companies would collect considerably more in wheeling revenue in the Stand-Alone case than in the Base case.

However, the change in wheeling rates in the Stand-Alone case and the existence of loop flow together result in considerable uncertainty regarding the wheeling impacts assessed to individual SPP companies. The use of tie-line flows to assess wheeling charge and wheeling revenue impacts when there are loop flows that would not represent actual transactions relies on the presumption that such loop-flow impacts will be similar in the Base and alternative cases and thus will not significantly impact the change in wheeling impacts between cases. However, if there is a significant change in wheeling rates between cases, for example the institution of intra-SPP wheeling charges in the Stand-Alone case, loop flow has the potential to distort measured wheeling impacts. The individual company Stand-Alone results with wheeling impacts included should therefore be viewed as representative, subject to further investigation into loop flow on individual company wheeling impacts. The collective Stand-Alone impact across SPP is a better measure than the individual company results, as the intra-SPP wheeling charges paid to or from SPP members offset one another in the collective calculation.

Table 5 Stand-Alone Case, Benefits (Costs) for Individual Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefits excl. Wheeling	Wheeling Impacts	Total Benefits
AEP	IOU	(19.8)	(3.0)	(22.8)
Empire	IOU	(5.8)	(19.8)	(25.6)
KCPL	IOU	(17.8)	68.7	50.9
OGE	IOU	(8.2)	(10.4)	(18.6)
SPS	IOU	(5.0)	49.5	44.5
Westar Energy	IOU	(17.0)	0.2	(16.9)
Midwest Energy	Coop	(7.9)	3.9	(3.9)
Western Farmers	Coop	1.3	(52.5)	(51.2)
SWPA	Fed	1.2	(20.9)	(19.7)
GRDA	State	(4.8)	(6.0)	(10.8)
Springfield, MO	Muni	(2.5)	6.1	3.5
Total		(86.3)	15.8	(70.5)

Table 6 shows how the results for the retail customers of the six IOUs in Table 5 are estimated to be distributed among the states in the region. As shown, the impact on most of the states is relatively modest.

Table 6 Stand-Alone Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

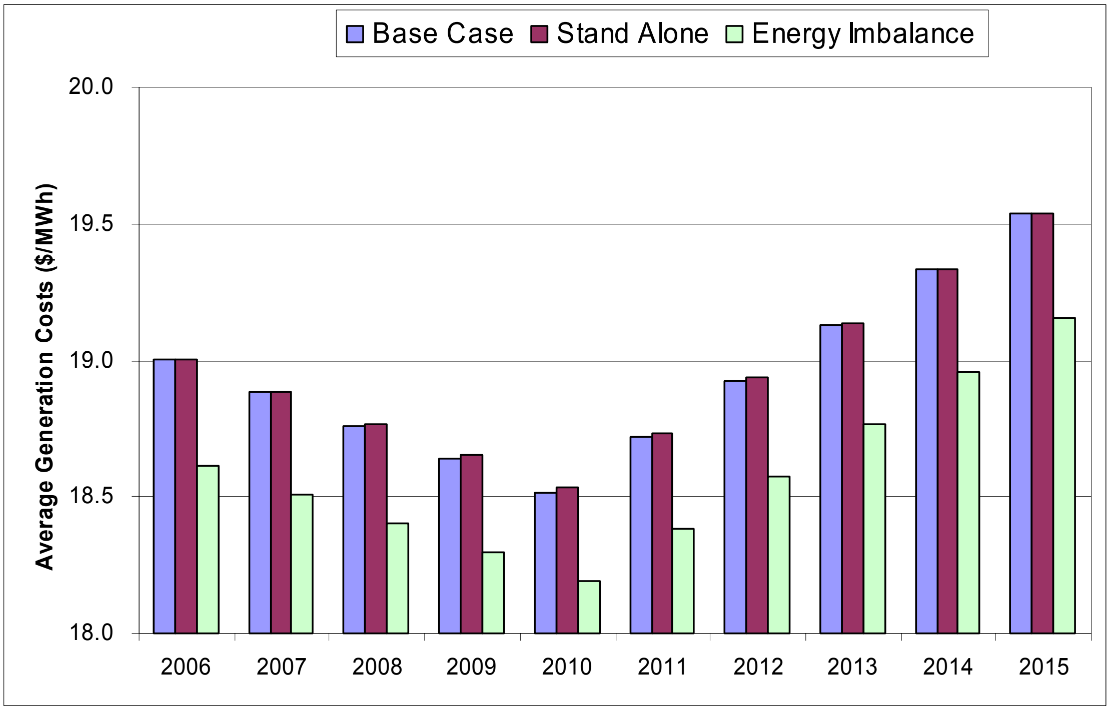
	Benefits excl. Wheeling	Total Benefits
Arkansas	(3.0)	(5.0)
Louisiana	(2.6)	(3.0)
Kansas	(22.2)	3.6
Missouri	(13.7)	2.7
New Mexico	(0.7)	5.9
Oklahoma	(16.2)	(25.9)
Texas	(5.5)	16.4

Wholesale Impacts to SPP

The Wholesale Energy Modeling process provided the energy-impact inputs to the allocated results discussed above. It also yields some high-level, region-wide wholesale market metrics related to the three cases simulated. Figure 1 shows the SPP average annual generation cost impacts resulting from the cases. (Note that the trend across the years is primarily due to non-case related factors such as fuel prices, transmission system upgrades, and load growth.) The difference between the respective average cost in each year reflects the fact that the institution of the EIS market increases dispatch efficiency (reduces generation, or production, cost[9]) by approximately 2% ($0.32 to $0.39 per MWh) and decreases SPP spot energy prices by approximately 7%. The Stand-Alone comparison with the Base case did not reveal significant differences. These results are consistent with the level of SPP-wide trade benefits discussed above in the individual case findings.

[9] Generation costs, or production costs, referred to in this report include start-up costs, variable operations and maintenance costs, fuel costs, and emissions costs.

Figure 1 Wholesale Aggregate Generation Cost Impacts



Qualitative Analysis of EIS Impacts

In addition to the quantified impacts discussed above, the long-run impacts of implementing a formal nodal EIS are expected to include improved transparency and improved price signals. Added complexities may produce adverse impacts during a transition period of roughly 3 to 5 years. In addition, applying explicit imbalance energy prices creates risks for market participants associated with not following schedules and may impede the development of competitive markets if the scheduling requirements are overly burdensome. The movement with the EIS to the centralized management of inadvertent energy will likely be subject to additional production efficiencies that are not captured in the quantitative results of the energy modeling.

Market Power Considerations

CRA has not conducted a formal study of market power in conjunction with this cost-benefit study. Two primary factors, of approximately equal strength, suggest that market power is not likely to become a significant consideration under the EIS market, in particular. These are (1) the provision for an ongoing market monitoring function within SPP and for a separate, independent monitor, and (2) the lack of incentive for the exercise of market power under the economic conditions likely to prevail under the EIS market. Market monitoring is required by FERC and should provide a substantial check on any potential to exercise market power after the implementation of the EIS market. The continuation of cost-based regulation for most of the output of generation in this region means that the EIS market is not likely to augment the incentive to exercise market power in a significant way.

Aquila Sensitivity Case Results

The Aquila wholesale energy market sensitivity case simulations showed that if Aquila were to affiliate with SPP there would be benefits to Aquila, though impacts to the surrounding regions were not necessarily affected in the same direction. The following are the major results.

- The overall benefits of the EIS market for SPP are not particularly sensitive to whether Aquila is in MISO or in SPP.
- While the SPP region's generating costs would be lower with Aquila in MISO (by $10 million under the Base case), Aquila's generating costs would be lower with Aquila in SPP (by $1.7 million in the Base case).
- Spot marginal energy costs are expected to be $0.16/MWh lower with Aquila in MISO under the Base Case and $0.26/MWh lower under the EIS case.
- Aquila companies generate more if in MISO under the Base case, but more if in SPP under the EIS case. (In both cases the change in Aquila generation is less than 1%.)
- Generators in SPP generate at higher levels if Aquila is in SPP than if it is in MISO under both the Base and EIS cases.
- Generation net revenues and the energy cost to serve load also indicate benefits for joining SPP for both Aquila companies.

1 Organizational Outline

This Cost-Benefit analysis report is organized as follows.

- Section 2 provides background and context for the analysis.
- Section 3 describes the energy modeling and the assessment of SPP market design, alternative impacts on energy flows, market dynamics, and energy pricing through the use of General Electric Company's quantitative generation and transmission simulation software, Multi-Area Production Simulation (MAPS). This analysis produced quantitative analytic results based on the economic and physical operation of the regional power system.
- Section 4 describes the benefits (costs) to individual SPP companies and states for the Base, Stand-Alone, and EIS cases.
- Section 5 describes the assessment of other qualitative impacts of the energy imbalance market.
- Section 6 describes the qualitative assessment of the market power impacts.
- Section 7 describes the methodology and results of the Aquila Sensitivity cases.

2 Background

This Cost-Benefit Analysis (CBA) was requested by the Southwest Power Pool Regional State Committee (RSC) to identify the costs and benefits to the State-regulated utilities of maintaining their transmission-owner membership in SPP under different scenarios. Doing that entailed two major activities:

1. Measuring costs and benefits that accrue from consolidated services and functions that include reliability coordination and regional tariff administration. This part of the CBA was accomplished through the development of revenue requirements for each SPP member, as adjusted for known and measurable changes arising from the various scenarios being analyzed, in order to project the results of future operations. The benefits were examined by performing energy system modeling and allocating the resulting costs and benefits to Investor Owned Utilities.

2. Analyzing the costs and benefits of SPP's implementation of a real-time Energy Imbalance Service (EIS) market. This was accomplished by comparing simulated energy benefits allocated to members with costs as reported by members and SPP.

In addition, the study examined the impact of Aquila being part of the SPP RTO.

While many industry cost studies have been done prior to this study, this study uniquely examined the implementation of only a real-time imbalance energy market as well as uniquely measured the impacts of moving back to a stand-alone utility structure. Appendix 2-1 provides a summary of other wholesale electric cost-benefit studies to date.

This report identifies, describes, and quantifies potential incremental costs and benefits with the intention that it be suitable for use by State Regulatory Commissions and/or individual companies in performing their own evaluations or assessments.

SPP is an independent, not-for-profit organization responsible for the reliable transmission of electricity across its 400,000-square-mile geographic area, covering all or part of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma and Texas. SPP's membership includes 14 investor-owned utilities, six municipal systems, eight generation and transmission cooperatives, three State authorities, and various independent power producers and power marketers. SPP also maintains a coordinating agreement with a federal power marketing agency.[10] In order to assess the benefits of SPP-RTO membership for each member, SPP's Strategic Planning Committee (SPC) decided that the SPP should coordinate a collective analysis to assess the net benefits to its members, rather than require its members to provide individual analyses. To implement this collective approach, the SPP Cost-Benefit Task Force (SPP-CBTF, or CBTF) was formed to select a consultant, if necessary, and to provide additional scope and guidance to the process. Subsequently, the RSC determined that it should contract for the analysis

[10] SPP and Southwest Power Administration (SWPA) have a coordination agreement in which SPP provides services to SWPA and SWPA complies with SPP's reliability criteria. SPP and SWPA's transmission systems are highly interrelated, and SWPA has on-going relationships with many SPP Transmission Owners.

to support the independence of the study. Charles River Associates' consultants[11] were selected to perform the study. Following the proposed methodology, CRA and the CBTF worked closely to develop the assumptions to be used in the analysis.

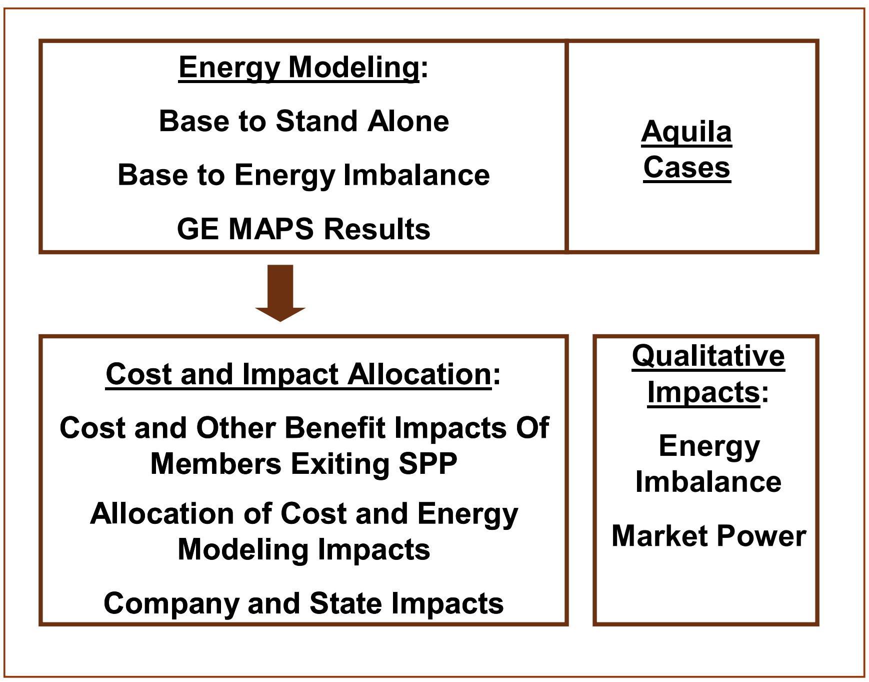
CRA presented status updates and detailed approaches throughout the study period. CRA and the CBTF members reviewed the results and refined the assumptions. This report presents the results of the modeling analyses and of the qualitative Cost-Benefit elements.

2.1 Cost-Benefit Analysis General Approach

This section introduces the general bodies of work constituting the Cost-Benefit analysis.

The SPP CBA consisted of four major elements, all based on a single set of defined cases, as shown in Figure 2-1.

Figure 2-1 Study Elements



Briefly, the study elements are as follows.

[11] Note that Tabors Caramanis & Associates in partnership with Charles River Associates were selected to perform the study. Subsequent to the selection, Tabors Caramanis & Associates was acquired by Charles River Associates.

a) **Wholesale Energy Modeling**—quantified impacts to the energy market, system dispatch, energy prices, and resulting production system costs, and provided the inputs to the allocation of impacts.

b) **Benefits (Costs) Allocation by Company and State**—provided a detailed record of cost and benefit impacts of the cases to the individual companies and to states.

c) **Qualitative Assessment of Energy Imbalance Impacts**—provided qualitative treatment of a variety of other measures of impact of the EIS not captured directly in the energy market modeling or allocations.

d) **Qualitative Assessment of Market Power Impacts**—provided qualitative treatment of the market power impacts of the EIS.

e) **Aquila Sensitivity Cases**—provided impacts on Aquila and SPP of Aquila being integrated into SPP rather than into the MISO RTO. It was decided by the CBTF that Aquila would not be modeled in SPP in the Base Case because it does not currently have its load under the SPP OATT.

A description of each of these five areas follows.

2.1.1 Wholesale Energy Modeling

The energy modeling addressed the expected impacts on the SPP energy market due to the different operational or system configuration assumptions in the various cases. The MAPS analysis included an assessment of the impact on production cost, on the dispatch of the system, and on interregional flows in the study area.

The system production cost associated with each market design alternative served as one metric for comparison among the scenarios. The energy modeling results also served as inputs to the allocation processes for further evaluation of impacts.

CRA modeled three operational market scenarios as part of the study:

- **Base Case:** SPP within its current footprint, no balancing market
- **EIS Case:** Energy Imbalance Service market (real-time) is implemented within today's SPP footprint
- **Stand-Alone Case:** SPP's FERC Order 888 compliant Open Access Transmission Tariff (OATT) is abandoned and each transmission owner operates under its own OATT.

These cases differed in their treatment of one or more of three primary characteristics: transmission wheeling rates, flowgate capacity, and dispatch of non-network generating units. The methodology and results of the wholesale energy modeling are presented in Section 3.

2.1.2 Benefits (Costs) Allocation by Company and State

Section 4 presents the sum of the impacts, including cost and energy modeling impacts. The allocation process distributed impacts across members and by state.

Whereas the wholesale energy modeling produces the system dispatch resulting from the various cases and provides some high-level regional metrics, the allocation process provided detailed company-specific and state metrics based on specific assumptions regarding regulatory policies and the sharing of trade benefits. The major categories of benefits and costs addressed in this study are as follows:

- Trade benefits
- Wheeling charges and revenues
- SPP EIS Market implementation and operating costs
- Individual utility EIS Market implementation and operating costs.

2.1.3 Qualitative Assessment of Energy Imbalance Impacts

Section 5 describes the assessment of energy imbalance market impacts other than those quantified in the modeling and allocation portions of the study. That is, while the energy market simulations addressed the energy efficiency aspects of the market design changes, there are other potential impacts that the simulation was not intended to address. The qualitative analysis results in a matrix of evaluations in which CRA consultants examined, on one hand, a number of characteristics of the markets being assessed (e.g., the real-time energy pricing policies or transmission right product design) against, on the other hand, a variety of metrics (such as volatility, risk, and competition).

2.1.4 Qualitative Assessment of Market Power Impacts

The Market Power Impacts section addresses the likelihood that the implementation of an EIS in SPP would enhance the potential for the exercise of market power in the SPP region, especially in the context of the market monitoring function and the continuation of cost-based regulation in this region.

2.1.5 Aquila Sensitivity Cases

Section 7 presents the results of the sensitivity cases in which Aquila is considered to be part of SPP rather than part of the MISO RTO. The SPP regional wholesale energy modeling results and the wholesale impacts on Aquila are provided. The sensitivity analysis is performed for the Base and EIS cases.

3 Wholesale Energy Modeling

CRA conducted a quantitative energy modeling of the SPP system under three scenarios: a Base case in which SPP continues to operate as an RTO; a Stand-Alone case, in which the members of SPP revert to operating as individual FERC Order 888 compliant transmission providers; and an EIS case in which SPP implements a formal energy imbalance market. The wholesale energy modeling used the MAPS model[12] and incorporated the operating procedures transmission constraints currently used in SPP. The analysis is intended to provide insight into the economic operation of the SPP energy market under each scenario.[13]

The results of the analysis are based on model representations and input assumptions developed through extensive discussions with the CBTF members and SPP operations and planning staff. The market design for the Base case was defined based on current operating practices. The design for the Stand-Alone case was based on input from the CBTF members about likely changes should members revert to acting alone. It was assumed that under the Stand-Alone case SPP would continue to act as a reliability coordinator and that members would participate in reserve sharing.[14] The Energy Imbalance case was modeled assuming that the system was dispatched centrally based on a least-cost representation. The final assumptions were ones that the SPP and utility members of the CBTF considered reasonably expected conditions for the years 2006 through 2015.

3.1.1 Input Assumptions

The following input assumptions were used in the wholesale energy modeling:

Company-specific load and energy forecasts based on 2004 EIA-411 data as provided by SPP for SPP companies, and most recent available EIA-411 data from the CRA data archive for areas outside of SPP

- 2002 hourly load shapes based on FERC 714 filings, as represented in the CRA data archive
- Gas and oil forecasts as described in the forecast memo
- Generation bids based on marginal cost[15] (fuel, non-fuel variable operations and maintenance, and opportunity cost of tradable emissions permits)
- Coal forecast as obtained from Resource Data International
- Transmission system configuration based on a load flow representation that includes all planned transmission upgrades, as provided by SPP

[12] MAPS is the Multi-Area Production Simulation software developed by General Electric Power Systems and proprietary to GE.
[13] MAPS does not simulate the regulation market, nor does it reflect AC system constraints such as the reactive power needs of the system.
[14] Operating Reserves are needed to adjust for load changes and to support an Operating Reserve Contingency without shedding firm load or curtailing Firm Power Sales. The SPP Reserve Sharing Program establishes minimum requirements governing the amount and availability of Contingency Reserves to be maintained by the distribution of Operating Reserve responsibility among members of the SPP Reserve Sharing Group. The SPP Reserve Sharing Program assures that there are available at all times capacity resources that can be used quickly to relieve stress on the interconnected electric system during an Operating Reserve Contingency. According to the SPP reserve sharing criteria, pool-wide reserve requirements are set as the size of the largest contingency plus one-half of the second-largest contingency. These requirements are then allocated among control areas in proportion to peak demand.
[15] Cost does not include any debt service, fixed O&M, or equity recovery in any of the cases' simulations.

- Environmental adders based on forecast emissions values[16]
- New generation additions already under construction based on public information and validated with the CBTF[17]

Appendix 3-1 (Input Assumptions) and Appendix 3-2 (Fuel Forecast Memo) give details of these and other inputs to the model.

3.1.2 Case Descriptions for Base case, Stand-Alone case, and EIS case

In distinguishing among these scenarios, CRA worked with three categories of modeling assumptions:

a) Application of wheeling charges
b) Effective flowgate capacity
c) Dispatch of non-network generating units

Table 3-1 indicates how these assumptions were treated in each scenario.

Table 3-1 Scenario Matrix

	Base Case	EIS Case	Stand-Alone Case
Application of wheeling charges	No wheeling charges between SPP members	No wheeling charges between SPP members	Area[18]-to-area wheeling charges (footnote the definition of Area)
Specification of flowgate capacity	Reduced flowgate capacity	Full flowgate capacity	Reduced flowgate capacity
Dispatch of non-network generating units	Sub-optimal	Optimal	Sub-optimal

Each of the three areas of distinction is discussed further below.

Wheeling charges. In MAPS, wheeling charges are calculated as a per-MW price adder for net flows from each area to each neighboring area, based on the definition of the control areas in the

[16] Emission rates are based upon EPA's Clean Air Markets database for 2002 and include future upgrades to emission control technology only if reported in this database. Future rates do not include any environmental controls likely to be required under the current Clean Air Interstate Rules, nor were any additional environmental controls included to reflect pending regulation and/or legislation

[17] Recently constructed combined cycle units were modeled with a heat rate and O&M costs characteristic of baseload combined cycle units. However, these units were not restricted to base load operational behavior, so it is possible that the production costs associated with these units may be underestimated relative to actual operations.

[18] Areas are defined in the power flow case supporting market simulations with MAPS. As a rule, areas specified in the power flow case correspond to control areas. MAPS determines tie-lines between areas and assesses user-defined wheeling charges on the net power flow across these tie-lines.

AC power flow case. MAPS automatically defines interfaces between areas, and CRA defined wheeling rates for each interface based on the scenario modeled and on the appropriate transmission tariff wheel-out rate.

Effective flowgate capacity. For the suboptimal dispatch cases (Base and Stand-Alone), transfer limits on all flowgates in the SPP region were decreased by 10% to reflect the inefficiency of congestion management through the TLR process. The 10% figure was determined in consultation with SPP based on historical tie-line flows during TLR events. Because of uncertainty in exactly which units will be redispatched under a TLR call, and because of the time lag inherent in this process, it is difficult to achieve full system utilization when congestion is managed through the TLR process.

Optimal vs. Sub-optimal dispatch of non-network generating units. MAPS models the optimal operation of an electric power system without regard to ownership or distinctions in priority and/or transmission network access rights among generating units. Under current SPP rules, however, resources designated as "network resources" for serving native load are given priority access to the transmission system in times of scarcity. It is generally assumed that network resources gain access to the transmission system and are dispatched on an economic basis. Resources that do not have network status receive access to the transmission system on a "first come, first served" basis, subject to the availability of transmission capacity. In order to simulate such a sub-optimal market outcome, the following approach is implemented:

- First, the system is simulated under conditions of optimal, security-constrained, non-discriminatory transmission access for all generating resources. This is identical to assuming the presence of an SPP-wide energy market, in which all committed generating units are dispatched to minimize system-wide production cost subject to transmission constraints. Congestion is relieved in real time on an economic basis in accordance with LMP market signals.

- Second, the system is simulated under the condition where two operational limitations are explicitly implemented in the model:
  - Generating units that do not have network status[19] but that adversely impact limiting transmission constraints are allowed to generate only to the extent that their impact on scarce transmission resources is minimal.[20] The effect is that these resources are dispatched only if they can obtain Available Transfer Capability (ATC), calculated on the basis of network resources having been dispatched first.[21] Given the modified dispatch of units that do not have network status, the rest of the system is redispatched so that the output reduction for non-network units is compensated by increased output of units that do have network status. This redispatch defines the sub-optimal case of the corresponding scenario.
  - In that second (sub-optimal) redispatch, operational limits on SPP flowgates are reduced from their operational limits by 10%, because congestion on these lines

[19] The list of non-network units was generated with extensive consultation with the CBTF.
[20] "Minimal impact" is defined as a flow of no more than 5% of the flow limit on any limiting resource.
[21] No firm economic purchases from the set of non-network units were assumed. To the extent that utilities purchase power from non-network resources to serve firm load and provide high-priority transmission access for this power under current market conditions, the savings between the Base case and the EIS case could be overstated.

is managed through the less-efficient transmission-line relief (TLR) process rather than through LMP-based generation redispatch.

Note that none of the cases included a "hurdle rate other than the tariff wheeling rates applied in the Stand-Alone case. Hurdle rates are non-tariff wheeling rates which are sometimes implemented in market simulations to represent unspecified or difficult-to-model inefficiencies or other barriers to trade. CRA and the CBTF discussed at length the use of a hurdle rate. However, CRA preferred implementing a method that emulated actual market characteristics (network access and conservative line loading under certain cases). As a result, the cases were represented by CRA as described above. Following the implementation of the methodology described above, the utility members of the CBTF reviewed the preliminary results of the simulations and found that simulated inter-control area flow patterns closely matched historical patterns. Based on this review, the addition of a simulation hurdle rate was determined to be unnecessary.

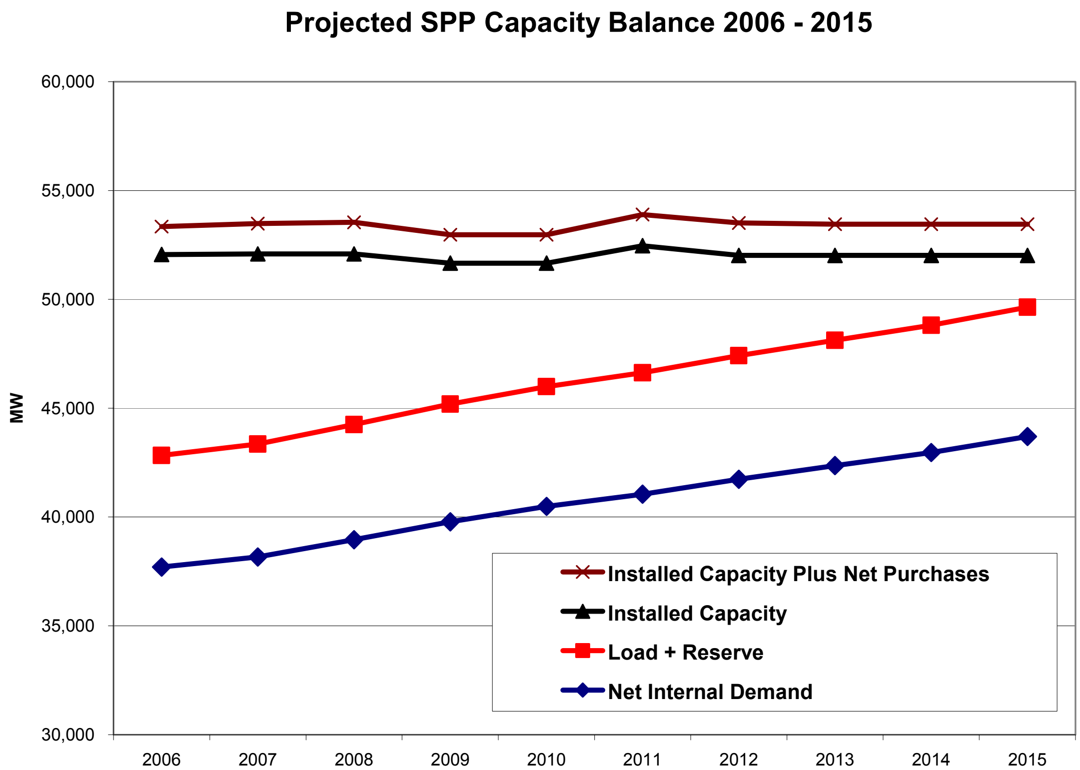
Note also that in each of modeling scenarios it is assumed that the entire volume of the market is cleared through the simulation's spot market. To the extent that transmission owners' self-dispatch and self-deployment is efficient and to the extent that the bilateral market is efficient, the results should emulate the existing market structures. However, to the extent that the bilateral markets are less efficient than the simulated result—and especially to the extent that one might expect the bilateral market efficiency to change with these cases—the actual results may deviate from the simulated results.

3.1.3 Resource Additions

Figure 3-1 summarizes the capacity balance forecast CRA prepared for the SPP region. The forecast is based on information provided by SPP companies with respect to peak demand requirements, generation capacity available to meet these requirements (including both company designated generating units and merchant power plants in SPP), and projected levels of firm purchases and sales.[22] The forecast included Cleco but not Aquila companies. The figure only reflects the addition of 30 MW of the Sunflower Windfarm in 2005 and 800 MW of Iatan 2 coal fired facility scheduled for 2010. It also reflects anticipated retirement of 430 MW of Teche generating units in 2008 and 440 MW of Rodemacher 1 generating unit in 2011. The overall projected capacity balance indicates that the capacity surplus will likely prevail over the study period. The assumed future mix of installed capacity will be more than sufficient for meeting SPP reliability requirements. That eliminated any need for modeling the entry of new generation in SPP. CRA also did not model generation retirements. A proper modeling of generation retirements would require making explicit assumptions with respect to the capacity market under each scenario considered. In absence of the capacity market model, economic retirement of generation cannot be assessed. Given that the capacity market could not be modeled consistently across all scenarios, and that the assessment of such a market is beyond the scope of this study, CRA decided not to model economic retirement of generating facilities in SPP.

[22] Net internal demand Peak demand, purchases, and sales data are per Form EIA 411 filings by SPP companies. Installed capacity in the study was based on CRA MAPS database and direct inputs by study participants.

Figure 3-1 Capacity Balance



3.2 Wholesale Energy Modeling Results

This section summarizes region-wide results of the MAPS wholesale energy modeling. Section 4 provides the detailed allocated results of the energy impacts. As is the case throughout this report, all financial values shown in this section are in real year-2003 U.S. dollars.

The quantification of benefits from the MAPS analysis is based on comparisons between the three cases[23] and includes generation production cost, regional generation, and the average spot market prices for energy. The comparisons are made across the SPP system.

The wholesale energy market modeling yields both high-level regional metrics and outputs that feed the detailed allocation results. Metrics include both physical metrics (generation in SPP or imports, and emissions impacts) and financial impacts such as prices.

[23] Capturing benefits in this way removes the majority of concerns regarding inaccuracies in modeling variables, because the great majority of parameters act equally in all cases. By examining differences between the cases, therefore, one can eliminate adverse impacts of a majority of modeling assumption inaccuracies.

3.2.1 Physical Metrics

This section presents both the physical market-wide impacts and the SOx and NOx production for SPP for all three cases.

Tables 3-2 through 3-6 give the physical metrics.

Table 3-2 Base Case Physical Metrics

Base Case					
Year	Generation (GWh)	Load (GWh)	Net Import (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	198,518	218,439	19,921	283,538	449,349
2007	201,109	221,942	20,834	282,606	446,861
2008	203,699	225,446	21,746	281,675	444,373
2009	206,290	228,949	22,659	280,744	441,886
2010	208,881	232,453	23,572	279,813	439,398
2011	210,828	235,843	25,016	282,211	442,057
2012	212,774	239,234	26,459	284,608	444,717
2013	214,721	242,624	27,903	287,006	447,376
2014	216,668	246,015	29,347	289,404	450,036
2015	218,615	249,405	30,791	291,802	452,695

Table 3-3 Stand-Alone Case Physical Metrics

SA Case					
Year	Generation (GWh)	Load (GWh)	Net Import (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	198,168	218,439	20,271	283,650	449,343
2007	200,825	221,942	21,117	282,903	447,162
2008	203,482	225,446	21,964	282,155	444,981
2009	206,139	228,949	22,810	281,408	442,800
2010	208,796	232,453	23,657	280,660	440,620
2011	210,686	235,843	25,158	282,954	443,094
2012	212,575	239,233	26,658	285,249	445,568
2013	214,465	242,624	28,159	287,543	448,042
2014	216,354	246,014	29,660	289,837	450,516
2015	218,244	249,405	31,161	292,131	452,991

Table 3-4 Imbalance Energy Case Physical Metrics

EIS Case					
Year	Generation (GWh)	Load (GWh)	Net Import (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	201,126	218,439	17,313	276,929	449,010
2007	204,115	221,942	17,827	275,616	446,033
2008	207,104	225,446	18,342	274,303	443,055
2009	210,092	228,949	18,857	272,990	440,077
2010	213,081	232,453	19,372	271,677	437,099
2011	215,348	235,843	20,495	273,580	439,816
2012	217,615	239,234	21,619	275,483	442,532
2013	219,881	242,624	22,743	277,385	445,249
2014	222,148	246,015	23,867	279,288	447,966
2015	224,414	249,405	24,991	281,191	450,682

Tables 3-5 and 3-6 show the differences in the physical metrics between the Stand-Alone and Base cases and between the EIS and Base cases.

Table 3-5 Impact of Stand-Alone Case - Physical Metrics

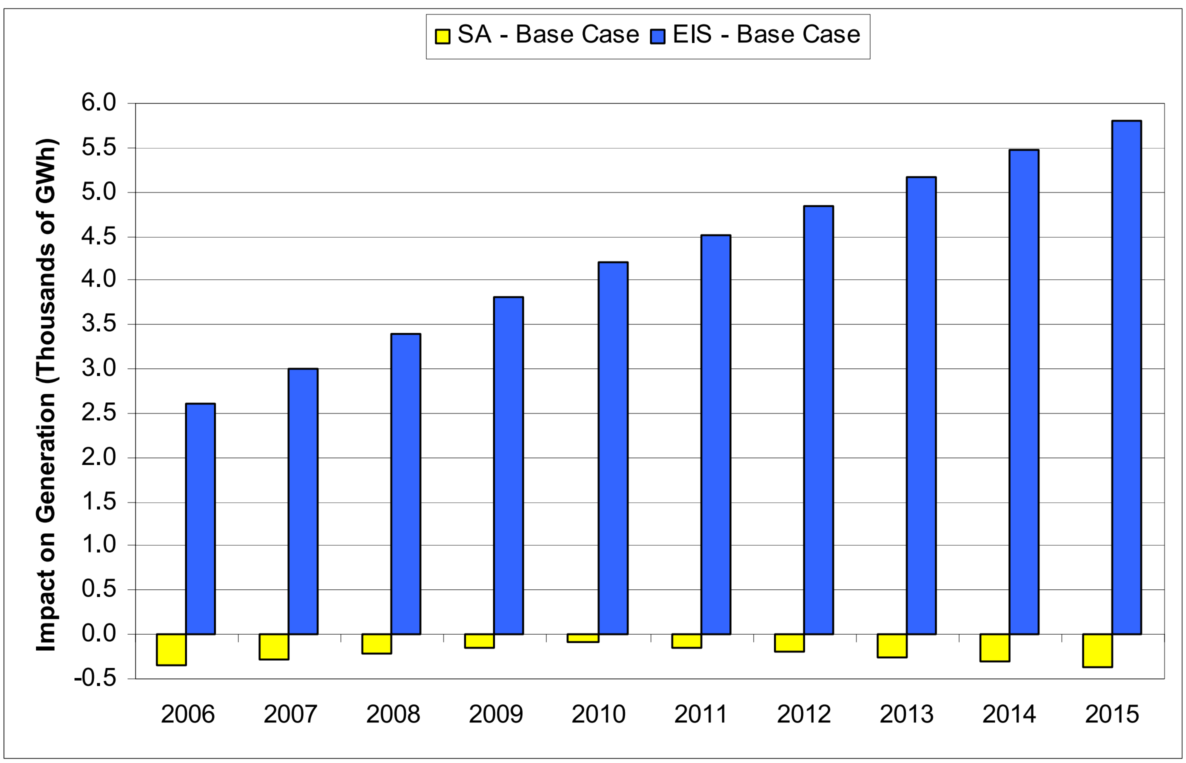
Impact (SA – Base)			
Year	Generation (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	(350)	113	(6)
2007	(284)	296	301
2008	(217)	480	608
2009	(151)	664	915
2010	(85)	848	1,222
2011	(142)	744	1,036
2012	(199)	640	851
2013	(256)	536	666
2014	(314)	433	481
2015	(371)	329	295

Table 3-6 Impact of EIS case—Physical Metrics

Impact (EIS – Base)			
Year	Generation (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	2,608	(6,608)	(338)
2007	3,006	(6,990)	(828)
2008	3,404	(7,372)	(1,318)
2009	3,802	(7,754)	(1,809)
2010	4,200	(8,136)	(2,299)
2011	4,520	(8,631)	(2,242)
2012	4,840	(9,126)	(2,185)
2013	5,160	(9,621)	(2,127)
2014	5,480	(10,116)	(2,070)
2015	5,800	(10,611)	(2,013)

Figure 3-2 shows the results of the different cases.

Figure 3-2 Impact of Stand-Alone (SA) and EIS cases on Generation in SPP Region

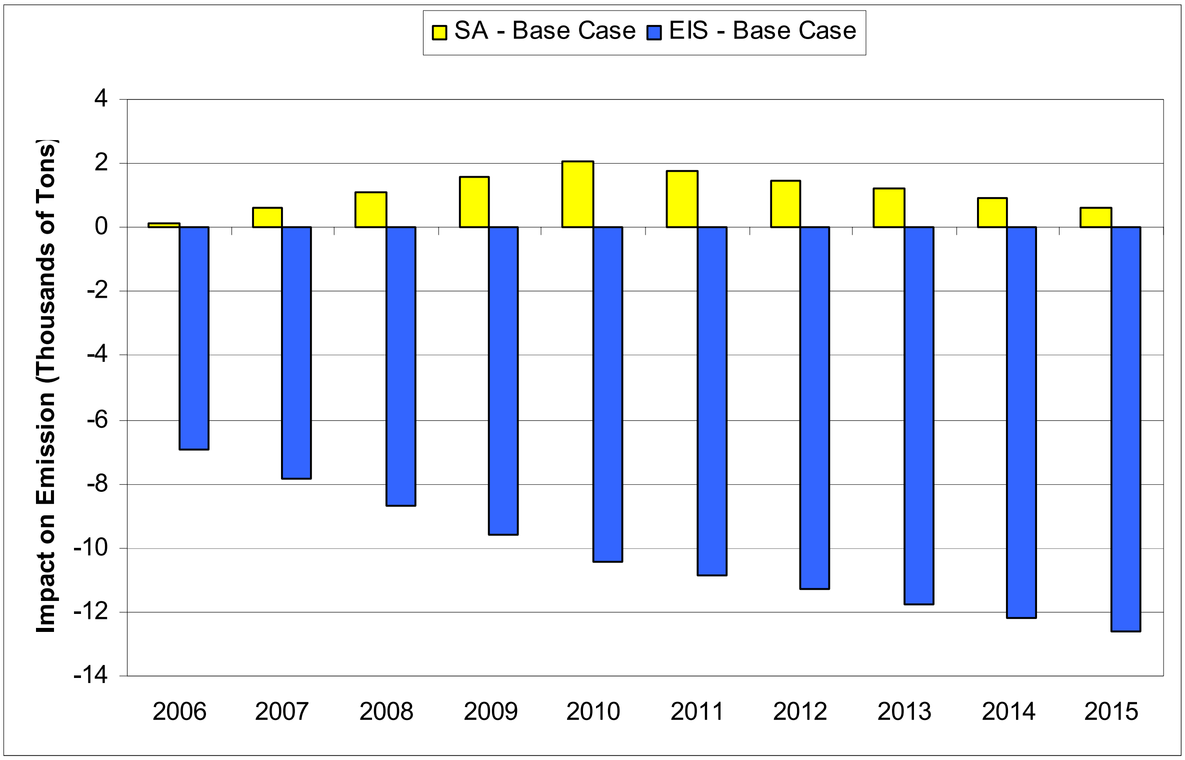


The simulations showed that generation within SPP would decrease were SPP to move from an RTO structure to a Stand-Alone structure in which wheeling rates would again exist between utilities that were previously SPP members. It is likely that with the added wheeling rates, the cost of production plus transmission renders power from SPP sources less competitive relative to generation outside of SPP, so that generation outside of SPP displaces generation within SPP.

In the EIS, case, however, an opposite result occurs. The EIS case results in a marked increase in generation in the SPP region due to the increased efficiency of the SPP dispatch as a result of the improved operation of the flowgate constraints and the increased ability for non-network units to be dispatched economically.

Figure 3-3 shows the impact of the Stand-Alone (SA) and EIS (EI) cases on regional emissions.

Figure 3-3 Impact of Cases on Emissions in SPP Region



The Stand-Alone case, given its further departure from the dispatch efficiency of the Base case due to wheeling rates, results in higher total emission in the SPP region. (Table 3-5 indicates that the increase is essentially equally spread between NOx and SOx emissions increases.) The modeling indicates that the movement to an imbalance energy market would result in a significant (up to 4%) decrease in emissions. Table 3-6 indicates the majority of the decrease is in NOx emissions. This is due to the shift in generation away from older, less efficient and higher emitting, steam-gas units in the Base case to more efficient, cleaner combined cycle units in the EIS case.

3.2.2 Annual Generation Costs—a critical economic indicator

Annual generation cost is a critical economic indicator. It is easy to interpret and it clearly represents a social gain (social welfare gain) to the region as a whole. In this study the terms "generation cost" and "production cost" are used interchangeably. The generation cost or production cost is for each generating unit includes start-up costs, variable operations and maintenance costs, fuel costs, and emissions costs.

Table 3-7 and Table 3-8 show the SPP generation costs24 by case and the impact on generation costs for the Stand-Alone and EIS cases, respectively. Figure 3-4 shows the average annual SPP generation cost for each case, and Figure 3-5 shows the cost differences between the Base case and the Stand-Alone and EIS cases.

Table 3-7 SPP Generation Cost ($/MWh) by Case

	Average Generation Cost Summary ($/MWh)		
Year	**Base Case**	**Stand-Alone**	**EIS**
2006	19.01	19.00	18.61
2007	18.88	18.88	18.51
2008	18.76	18.77	18.40
2009	18.64	18.65	18.30
2010	18.51	18.54	18.19
2011	18.72	18.74	18.38
2012	18.92	18.94	18.58
2013	19.13	19.14	18.77
2014	19.33	19.34	18.96
2015	19.54	19.54	19.15

[24] In the allocation analysis, all control areas are defined to correspond with the areas defined in the load flow case, and units are assigned to companies in accordance with their electrical locations regardless of financial ownership. This is required for alignment with tie line flows, which are defined according to the load flow case areas. In contrast, the wholesale market analysis identifies units according to ownership data provided by the CBTF. Because of this, some differences in electrical output and generation cost by company and over SPP will be found between the two analyses.

Table 3-8 Impact of Cases on Average Generation Cost in SPP ($/MWh)

	Impact on Generation Cost ($/MWh)	
Year	**SA – Base**	**EIS – Base**
2006	(0.005)	(0.39)
2007	0.002	(0.37)
2008	0.008	(0.36)
2009	0.015	(0.34)
2010	0.021	(0.32)
2011	0.016	(0.34)
2012	0.012	(0.35)
2013	0.007	(0.36)
2014	0.003	(0.37)

Figure 3-4 SPP Generation Cost ($/MW) by Case

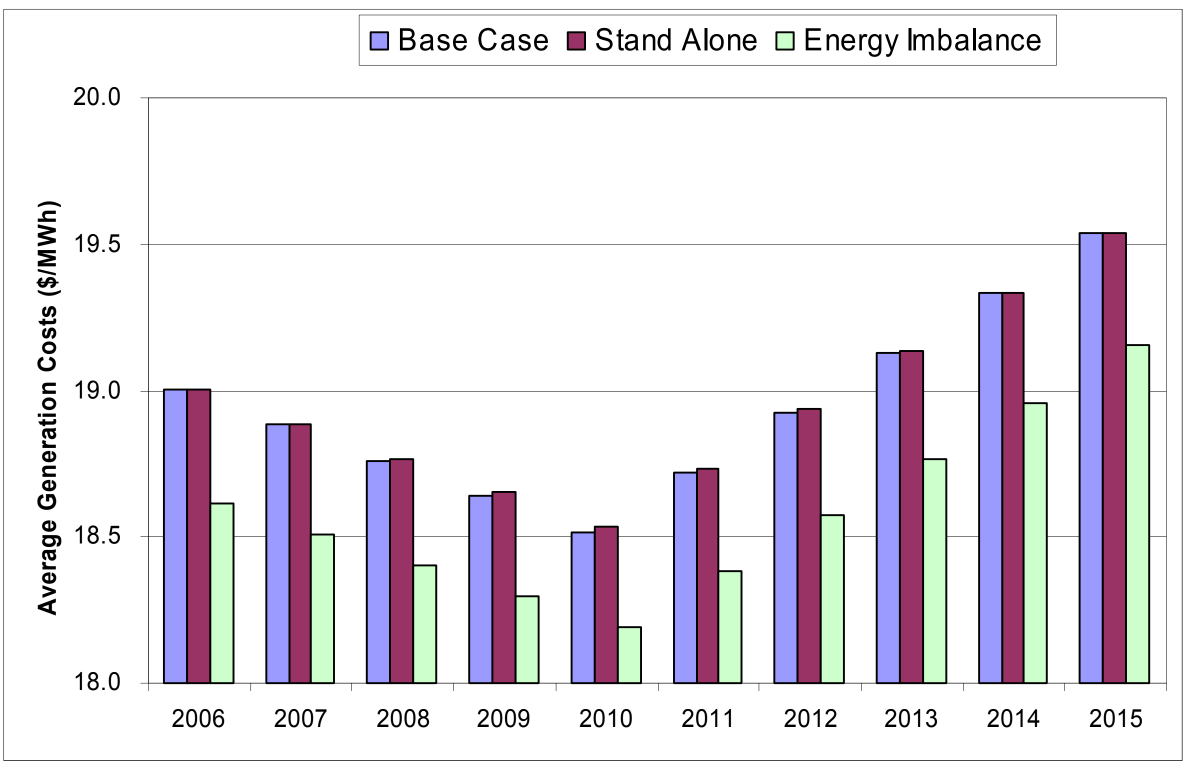
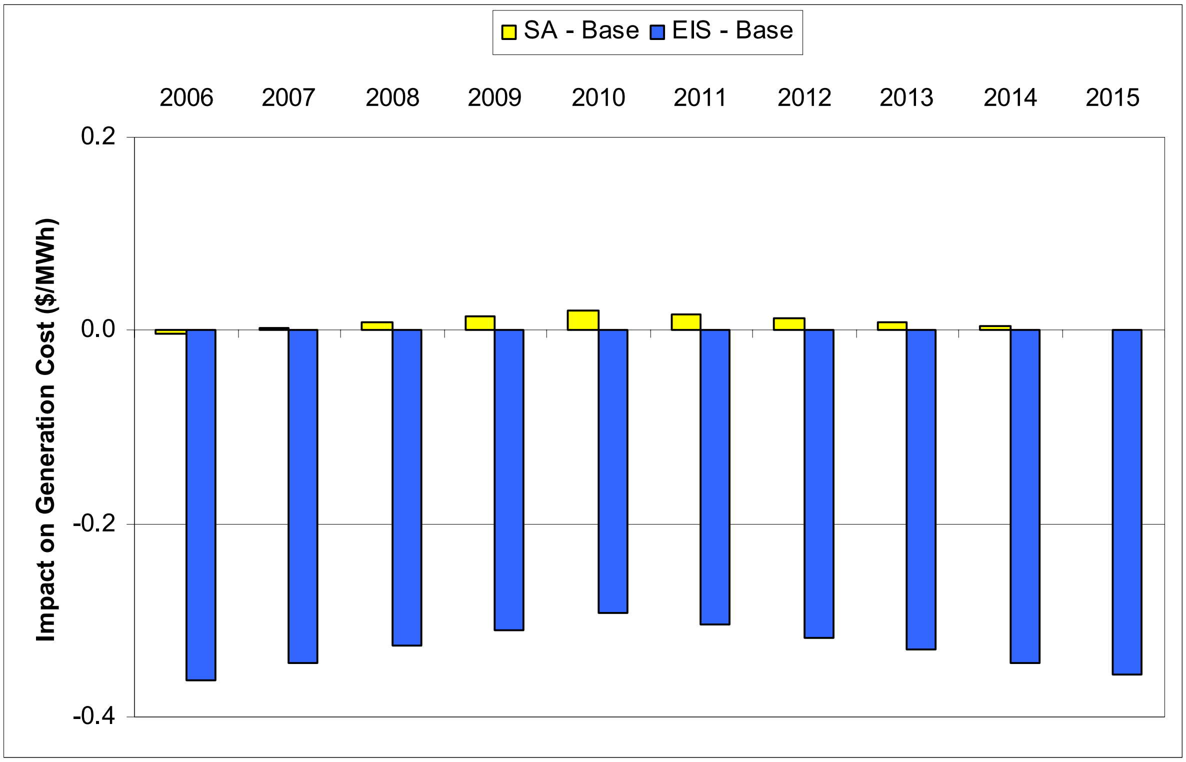


Figure 3-5 SPP Generation Cost ($/MWh) Differences



The wholesale results indicate a year-by-year pattern, as well as regular pattern in the case differences. There are three main factors behind the year-by-year trend of the cost differences.

- First, generation costs, and therefore generation cost differentials between scenarios, are significantly influenced by underlying forecast fuel prices. Assumed natural gas prices at Henry Hub are as follows:

  - $5.54/MMBtu in 2006
  - $4.24/MMbtu in 2010
  - $4.47/MMbtu in 2014

  That would imply generation costs in 2006 being higher than in 2010 and generation costs in 2010 being lower than in 2014. The same pattern will likely apply to changes in generation costs between scenarios—the change in 2006 would be higher than in 2010, then change in 2010 would be lower than in 2014.[25]

- Second, changes in the transmission system occur over the study horizon. The load flow case used to simulate years 2010 and 2014 includes transmission upgrades not available in 2006. Simulations for 2010 would reflect these transmission upgrades and therefore could exhibit less transmission congestion than in 2005. As discussed above, sub-optimal dispatch underlying the Base case modeling is primarily influenced by transmission congestion; lower congestion implies

[25] It is important to note that direct simulations were performed for 2006, 2010, and 2014 only. Results for other years are based on interpolation and/or extrapolation.

smaller differences between EIS and Base case scenarios, as can be observed in comparing years 2006 and 2010.

- Third, there is load growth requiring greater generation output but not supported by further transmission upgrades: simulations for 2010 and 2014 were made using the same load flow case. That implies higher congestion in 2014 than in 2010. Higher congestion in turn implies less efficient use of non-network generators and therefore greater difference between the Base and EIS case scenarios in 2014 than in 2010, as can be seen in Figure 3-5.

Implementation of the EIS market yields a saving of $0.36 per MWh on average. The relative magnitude of the generation cost difference between the Base and Stand-Alone cases is essentially negligible (less than 0.01%). Thus the modeling found no significant *region-wide* impact of moving from the Base case to the Stand-Alone case.

3.2.3 Wholesale Spot Energy Price Changes

This section presents the impacts on the spot price[26] of energy in SPP from the three cases. Table 3-9 shows the average annual energy cost in the SPP region under each case, and Table 3-10 shows the change in spot price, relative to the Base case, for the Stand-Alone and EIS cases.

Table 3-9 Average SPP Spot Load Energy Price

	Costs of Served Load Summary ($/MWh)		
Year	**Base Case**	**Stand-Alone**	**Energy Imbalance**
2006	40.85	40.95	38.32
2007	39.96	40.07	37.49
2008	39.06	39.19	36.67
2009	38.16	38.31	35.85
2010	37.27	37.43	35.03
2011	37.92	38.01	35.45
2012	38.57	38.59	35.87
2013	39.22	39.18	36.29
2014	39.87	39.76	36.71
2015	40.53	40.34	37.13

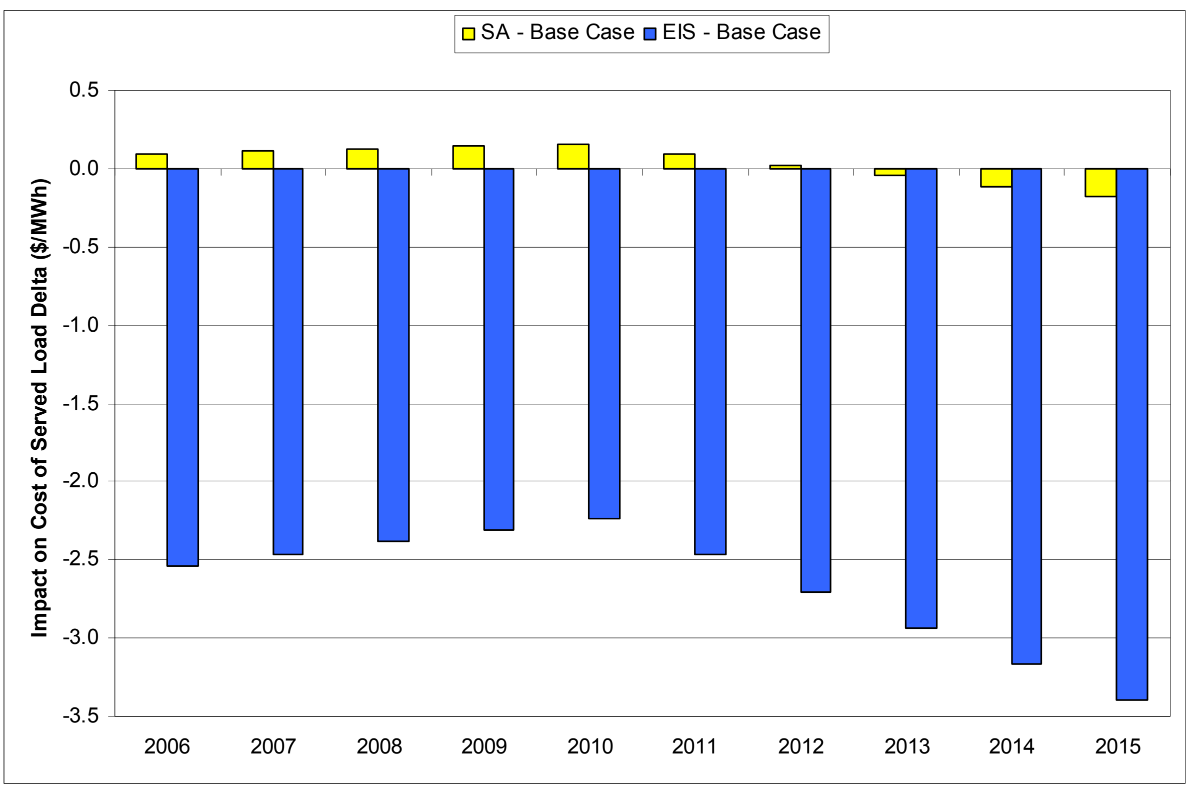
[26] The "spot price" refers to the locational price of energy (in $/MWh) as calculated under the locational marginal price (LMP) system, assuming cost-based, security constrained optimal dispatch of the system. While a spot price can be calculated for any point in the system, it is not generally reflective of the cost of production at that location, but it is reflective of the marginal cost of increasing consumption at that location.

Table 3-10 Case Impacts on SPP Spot Energy Price

Average Cost of Served Load Delta ($/MWh)		
Year	**SA - Base case**	**EIS - Base case**
2006	0.09	(2.54)
2007	0.11	(2.46)
2008	0.13	(2.39)
2009	0.14	(2.31)
2010	0.16	(2.24)
2011	0.09	(2.47)
2012	0.02	(2.70)
2013	(0.04)	(2.93)
2014	(0.11)	(3.17)
2015	(0.18)	(3.40)
Average	**0.04**	**(2.66)**

Figure 3-6 shows the impact of the Stand-Alone and Energy Imbalance cases on the average load spot energy price in SPP.

Figure 3-6 Stand-Alone and EIS Case Impact on SPP Spot Energy Price



Note that the general patterns of the impacts are similar to those shown for generation costs in Figure 3-5, but that the regional load marginal energy cost differences between the cases are significantly higher because of the model's marginal pricing of spot energy to loads. For the Energy Imbalance case, the spot price for loads is over $2.50/MWh (about 7%) less expensive than under the Base case scenario on average over the study horizon.

3.2.4 Impact on the Marginal Value of Energy Generated

Similar to Section 3.2.3, this section provides the impacts of the cases to the marginal value of energy at the generation sources. Table 3-11 shows the average marginal value of the energy for all generation in SPP and Table 3-12 shows the difference in marginal value of the generation between the cases. These results indicate how the spot value of energy at the generating locations is impacted by the cases in the simulations.[27]

Table 3-11 Average Marginal Value of Energy Generated

Average Marginal Value of Energy Generated ($/MWh)			
Year	**Base Case**	**Stand Alone**	**Energy Imbalance**
2006	37.40	37.28	35.39
2007	36.55	36.47	34.64
2008	35.73	35.68	33.91
2009	34.93	34.92	33.19
2010	34.15	34.17	32.50
2011	34.70	34.65	32.81
2012	35.35	35.22	33.21
2013	35.99	35.78	33.60
2014	36.62	36.34	33.99
2015	37.23	36.88	34.37
Average	**35.86**	**35.74**	**33.76**

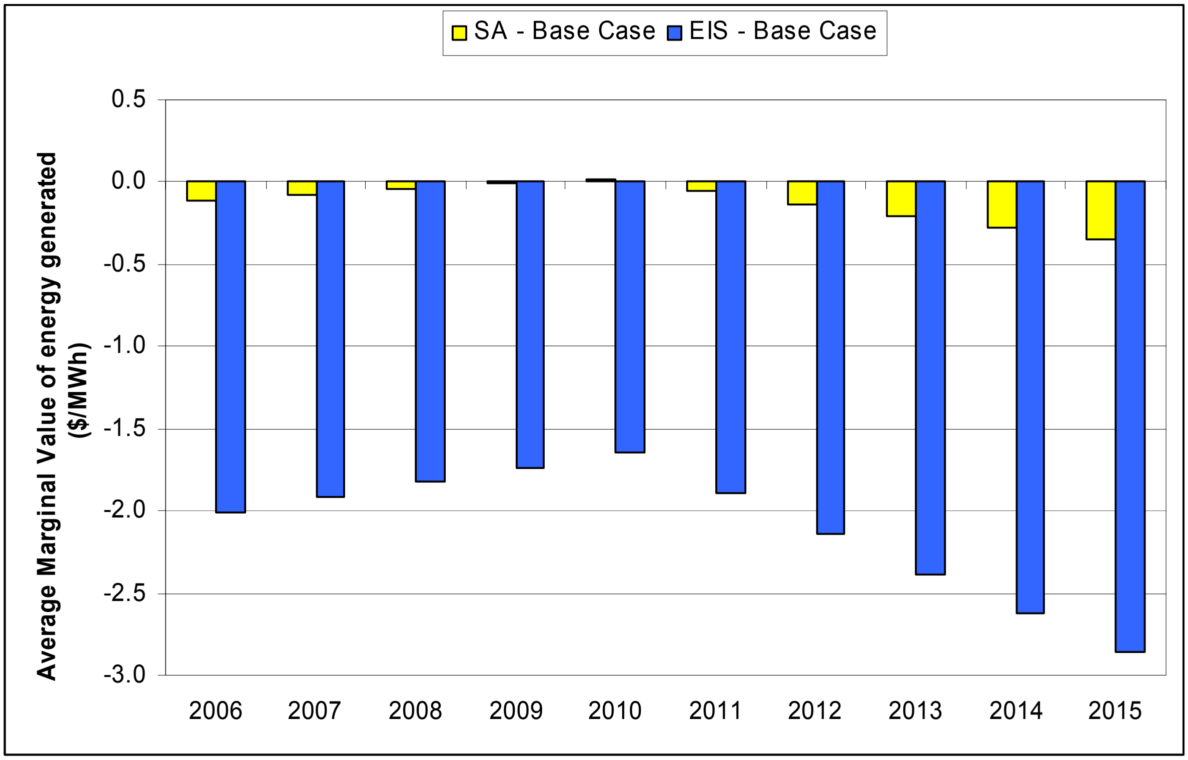
[27] Recall that the simulated values are based on the assumption that generating units bid marginal cost.

Table 3-12 Average Marginal Value Delta

Average Marginal Value Delta of Energy Generated ($/MWh)		
Year	**SA - Base Case**	**EIS - Base Case**
2006	(0.12)	(2.01)
2007	(0.08)	(1.91)
2008	(0.05)	(1.82)
2009	(0.01)	(1.74)
2010	0.02	(1.65)
2011	(0.06)	(1.90)
2012	(0.13)	(2.14)
2013	(0.21)	(2.39)
2014	(0.28)	(2.63)
2015	(0.35)	(2.86)
Average	**(0.13)**	**(2.11)**

Figure 3-7 shows the differences in marginal energy value between the cases. The figure reflects the fact that the value of energy for generators is lower in the EIS case than in the Base case (on average by $2.11). The value of energy to the generators simulated in the Stand-Alone case is also lower than in the Base case. The imposition of wheeling rates in the Stand-Alone case causes the marginal value of energy at the generators to increase for some companies and to decrease for other companies. Figure 3-7 simply shows the result of these impacts and indicates that the total average marginal generation energy value happens to be slightly lower under the Stand-Alone case.

Figure 3-7 Average Marginal Value of Energy Generated



3.2.5 Outputs to Allocation Model

In addition to providing high-level regional indicators of the impacts of each of the cases, the Wholesale Energy Modeling provided critical inputs to the allocation processes that led to company and state-specific impacts. These inputs include the following:

- Generation
- Generation cost (including emission costs)
- Nodal locational marginal prices
- Hourly tie-line flows
- Annual generating unit reports including dispatch, cost and revenue data by plant
- Load

3.3 Wholesale Energy Modeling Conclusions

The wholesale energy modeling SPP generation cost and spot energy price metrics indicate that the Energy Imbalance market increases the dispatch efficiency (reduces dispatch cost) by approximately 2% and decreases SPP spot energy prices by approximately 7%. These are significant differences. The differences between the Stand-Alone and Base case metrics were much smaller than those between the Base Case and EIS scenarios. Thus, in the absence of an Energy Imbalance Service market, reversion to a Stand-Alone mode of operation would not appear to have a significant adverse impact on regional dispatch efficiency. However, as discussed in Section 4, reversion to a Stand-Alone mode would create significant shifts in generation costs between transmission owners, merchant generators, other SPP market participants, and neighboring regions.

4 Benefits (Costs) by Company and State

4.1 Methodology for Measuring Benefits (Costs)

Welfare for regulated customers of a utility, as measured in this study, is based on the charges to local area load for generation and transmission service, assuming that any benefits to the regulated utility are passed through to its native load. If these charges decrease, regulated customer welfare increases. This study assesses the benefits and costs associated with load-serving utilities moving from base conditions to stand-alone status and from the base conditions to participation in the EIS market. To quantify this change, CRA identified and analyzed potential sources of benefits and costs that impact the charges for generation and transmission service, such as generation or production costs, energy purchases, wheeling charges, and O&M expenditures.

The major categories of benefits and costs addressed in this study are trade benefits, wheeling charges and revenues, SPP implementation and operating costs, and individual utility implementation and operating costs. Trade benefits and wheeling impacts were computed using the MAPS results for each case.[28] The changes in SPP costs from the Base to the Stand-Alone case and from the Base to the EIS case were estimated using projected SPP budgets. Individual company changes in operating and capital costs that would take place under stand-alone status and under participation in the EIS market were projected by each company, reviewed by CRA for consistency in approach, and converted to revenue requirements. The methodology used to estimate the impact of each major category of benefits and costs is discussed below.

4.1.1 Trade Benefits

The cases analyzed in this study (Base, Stand-Alone, and EIS) reflect varying degrees of impediments to trade between regions. In particular, the institution of intra-SPP wheeling rates in the Stand-Alone case results in greater impediments to trade between utility areas, and institution of the EIS market results in reduced impediments to trade between utility areas. Reductions in the impediments to trading between utilities should generally result in production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they comprise fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the “trade benefits” referred to in this study.

Increases or decreases in production cost in any particular utility area, by themselves, do not provide an indication of welfare benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions. For example, a utility that increases its exports would have higher production costs (because it generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered. Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance--an increase in imports or exports—an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area welfare. Increased trading activity provides benefits to both buying parties (purchases at a lower cost than owned-generation

[28] MAPS runs were completed for the years 2006, 2010 and 2014. The results for the intervening years were interpolated on a straight-line basis using the results in 2003 dollars, and then an annual inflation rate of 2.3% was applied. Results for the year 2015 were obtained by escalating 2014 results at the annual inflation rate.

cost) and selling parties (sales at a higher price than owned-generation cost). In practice, the benefits of increased trade are divided between buying and selling parties. For example, the "split-savings" rules that govern traditional economy energy transactions between utilities under cost-of-service regulation result in a 50-50 split of trading benefits. While production cost changes cannot be used directly to allocate trade benefits to individual utility areas, the individual utility trade benefits will sum to the change in aggregate production cost.[29]

In this study, merchant plants are assumed to be participating in the wholesale market based upon market-driven pricing in the Stand-Alone, Base, and EIS Market cases. All utility-owned plants are assumed to have an obligation to serve native load under cost-based regulation. Benefits are therefore calculated as if all trade gains earned by utilities accrue to the benefit of native load. This means that benefits have not been separated between those that might accrue to the utility in comparison to those that that might accrue to that utility's native load.

Traditional cost-of-service regulation differs from a fully deregulated retail market, in which individual customers and/or load-serving entities buy all their power from unregulated generation providers at prevailing market prices. In such a deregulated market, benefits to load can be ascertained mostly in terms of the impact that changes to prevailing market prices have on power purchase costs. For the SPP region, in which cost-of-service rate regulation is in effect, the energy portion of utility rates reflects the production cost for the utility's owned generating units, plus the cost of "off-system" purchased energy, net of revenues from "off-system" energy sales. In turn, utility customers under cost-of-service regulation pay for the fixed costs of owned-generating units through base rates. Allocating system-wide energy benefits to each SPP utility thus requires an analysis of both the production cost of operating utility-owned generating plants and the associated utility trading activity (purchases and sales).

In this study, trade benefits are allocated primarily among utilities within SPP and control areas with direct interties with SPP based on the change in utility generation between the base and change cases.[30] This presumes that trading margins are similar throughout the SPP region. This approach differs from that used in CRA's SEARUC cost-benefit study, which was based on using a 50-50 sharing rule and tie-line flows as a proxy for transactions between adjoining control areas. Our consideration of using a similar method within SPP indicated that loop flow effects are important within this compact region and would prevent a successful application of the SEARUC approach without substantial modification. CRA believes that the assumption of a similar trade margin throughout SPP provides a good first approximation of how aggregate trade benefits are likely to be distributed within SPP. Improving on this estimate would require additional study to determine how the loop flow issue could be addressed in greater detail.

In particular, this study assumes that trade gains are shared among control areas in proportion to the magnitude of the absolute value of the change in generation output. This means that control areas that

[29] To help understand why this must be so, consider a simple two-company example. Assume there is a $16 marginal cost to generate in Company A's control area and a $20 marginal cost to generate in Company B's control area and there is no trade. Now assume through a reduction in trade impediments that 1 MW' can be traded from A to B over the inter-tie between A and B. Company A will generate 1 MW more at a production cost of $16, while Company B will generate 1 MW less at a production cost savings of $20. Thus, the total saving in production cost is $4 (i.e., $20 – $16). If the trade price is set, for example, at a 50/50 split savings price, Company A will receive $18, for a trade benefit of $2 ($18 – $16), and Company B will pay $18, for a trade benefit of $2 ($20 – $18). The total trade benefits of $4 ($2 + $2) will match the total production cost saving of $4.

[30] For purposes of this study, the change in utility generation was assessed on an annual basis. This allocation could be further refined through the use of a monthly or hourly allocation.

sell more energy (those whose generation increases) and control areas that buy more energy (those whose generation decreases) share the trade benefits equally for each megawatt-hour of change in generation output. Within each control area, trade benefits associated with changes in utility-owned generation accrue to native load. This is consistent with traditional trading between utilities using a 50-50 sharing arrangement. The only difference between this approach and that used in the SEARUC study is that the 50-50 sharing rule is implemented in this study based on changes in each utility's position as a net buyer or seller, while the 50-50 sharing rule in the SEARUC study was implemented between interconnected pairs of utilities. The level of aggregation used in the allocation of the trade benefits is higher in this study, but the underlying approach is the same—a 50-50 sharing rule.

The study makes the additional assumption that merchant units participate in the EIS market in a particular way. The EIS market will provide an SPP-wide opportunity for merchant units to participate in an organized spot market for energy. However, it is expected that most merchant plants will do so through some type of contractual arrangement with utilities on behalf of their native load. CRA does not have any information about the potential nature of such contractual arrangements. However, it is unlikely that merchant plants would participate in an imbalance market for energy if that market were the sole source of merchant revenue. Merchant plants likely would seek additional revenue through contractual arrangements with native load.

Accordingly, CRA has assumed that merchants participate in the EIS under a two-part pricing arrangement. First, the merchants are paid their respective locational wholesale price for any energy that they produce. Second, the merchants in each control area are allocated a share of the control area trade benefits based on their change in generation output. That is, the control area trade benefits are allocated to utility-owned generation and merchant generation within the control area based on the absolute value of their change in generation output. Finally, the resulting merchant allocation of trade benefits is further subdivided with the merchants receiving 50 percent of these trade benefits, while native load receives the remaining 50 percent under contractual arrangements. The 50 percent native load share of these trade benefits is allocated on a pro rata basis to all of the participating load in the EIS market. In effect, CRA is using an estimate of the trade benefits allocable to the merchants as a basis for a 50-50 sharing formula between merchants and native load. This is consistent with the 50-50 sharing rule used to allocate trade benefits between control areas discussed above, except that the merchant/utility sharing arrangement would be implemented within a control area. We recognize that this approach provides only a preliminary indication (but a reasonable one, in our view) of how merchant participation might evolve in the future.

4.1.2 Wheeling Impacts

Using the MAPS outputs, wheeling charges and revenues are calculated based on hourly tie-line flows in MAPS multiplied by the applicable wheeling rate. Wheeling charges are paid on "out" transactions, i.e., exports from each control area, and are paid by the load in the importing control area. The wheeling charges are paid to the transmission provider in the exporting control area. These wheeling revenues reduce the net transmission revenue requirement to be paid by the native load in the exporting transmission provider's control area. Since each import is associated with a matching export, wheeling charges and wheeling revenues will match over the entire modeled footprint.

For the transmission owners under the SPP Tariff, wheeling revenues collected by SPP are distributed to individual SPP transmission owners based on a formula that includes MW-mile and other impacts. For purposes of this study, the wheeling revenues calculated using MAPS tie-line flows were redistributed among these transmission owners using each transmission owner's percentage share of 2003 revenue by transmission owner for point-to-point Schedule 7 and 8 external transactions.

4.1.3 Administrative and Operating Costs

A number of costs must be analyzed in addition to those directly addressed in MAPS. These include SPP implementation and operating costs that are ultimately paid by member companies and operating and implementation costs that are incurred directly by member companies.

SPP costs were analyzed using SPP budget forecasts, disaggregated as necessary to identify costs that would change in the Stand-Alone and EIS Market cases. In response to CRA requests, each company provided a projection of the implementation and operating costs it would incur. Individual company responses were compared and discussed in order to ensure a consistent approach among the respondents.

The specific categories of costs addressed in this study are discussed in detail below for each case.

4.2 Stand-Alone Case Results and Discussion

4.2.1 Trade Benefits

Implementation of intra-SPP wheeling rates in the Stand-Alone case leads to a less efficient dispatch and thereby yields additional system-wide production costs. Additional production costs for the Eastern Interconnect are $54 million over the study period. Production costs for the transmission owners under the SPP tariff increase by $165 million, while, in contrast, production costs of SPP merchants decrease by $107 million. As discussed above, these production cost impacts are shared among individual companies through trading. Using the methodology outlined above, the aggregate Stand-Alone trade impacts for the transmission owners under the SPP tariff are $21 million of lost (i.e., negative) benefits. That is, the Stand-Alone case results in a decrease in trade benefits for the transmission owners under the SPP tariff, and thus an increase in costs. Through the allocation process, transmission owners under the SPP tariff incur 39% ($21/$54) of the total loss in trade benefits across the Eastern Interconnect.

Tables 3, 4 and 5 in Appendix 4-1 give annual trading benefit results, production cost changes, and generation changes by company over the study period.

4.2.2 Transmission Wheeling Charges

Implementation of intra-SPP wheeling rates leads to significantly greater wheeling charge payments by SPP companies. As noted above, the native load in each control area was assumed to pay the charges associated with the import of power. The wheeling charges increase by $500 million over the study period for the transmission owners under the SPP tariff. Since these are payments, this is a negative benefit to the Stand-Alone case. Table 6 in Appendix 4-1 gives annual wheeling charge increases by company over the study period.

4.2.3 Transmission Wheeling Revenues

Similarly, the implementation of intra-SPP wheeling rates leads to significantly greater wheeling revenue collections by SPP transmission providers. The wheeling revenues are paid to the exporting control area's transmission provider, and then allocated to the native load in that control area. That is, wheeling revenues are used to reduce the transmission revenue requirement for native load. The wheeling revenues for the transmission owners under the SPP tariff increase by $516 million. Since these are revenues, this is a positive benefit to the Stand-Alone case.

As discussed above, the wheeling revenues were calculated using MAPS tie-line flows for the transmission owners under the SPP tariff. The revenues were redistributed among the transmission owners using each transmission owner's percentage share of 2003 revenue for point-to-point Schedule 7 and 8 external transactions. Table 7 in Appendix 4-1 gives annual wheeling revenue increases by company over the study period.

The use of tie-line flows to assess wheeling charges and wheeling revenue impacts when there are loop flows that would not represent actual transactions relies on the presumption that such loop flow impacts will be similar in the Base and alternate cases and thus will not significantly impact the change in wheeling impacts between cases. However, in the case in which there a significant change in wheeling rates between cases, for example the institution of intra-SPP wheeling charges in the Stand-Alone case, the impact of loop flow on intra-SPP tie-line flows has the potential to distort measured wheeling impacts. Given that possibility, the specific company wheeling impacts (both wheeling charges and wheeling revenues) in moving from the Base Case to the Stand-Alone case presented in this study should be viewed as representative results meriting further review and analysis.

4.2.4 Costs to Provide SPP Functions

In addition to its long-running role as a NERC reliability council, SPP performs a number of other reliability/transmission provider functions for transmission-owning members, namely reliability coordination, tariff administration, OASIS administration, available transmission capacity (ATC) and total transmission capacity (TTC) calculations, scheduling agent, and regional transmission planning. Moving to stand-alone status would require the transmission owner to procure these services from an alternative supplier or provide them internally. In turn, however, the transmission owner would avoid payment (through the assessment process) to SPP for SPP's provision of these functions.

Appendix 4-3 provides a discussion of the analysis performed to estimate the differential in costs to provide these functions. That analysis indicates that the transmission owners under the SPP tariff would incur additional costs of $46.0 million over the study period. Since this is an additional cost, this is a negative benefit to the Stand-Alone case.

Some companies would incur a decrease in the net costs for these functions, corresponding to a positive benefit. Table 8 in Appendix 4-1 presents the costs, by company, under the Base and Stand-Alone cases.

Since SPP supplies these functions in both the Base and EIS Market cases, this cost category is not relevant to the comparison of those cases.

4.2.5 FERC Charges

All load-serving investor-owned utilities must pay annual FERC charges in order for FERC to recover its administrative costs. Historically, these FERC charges have been assessed to individual investor-owned utilities based only on the quantity of the utility's wholesale transactions (i.e., those related to interstate commerce). However, the annual FERC charges for SPP RTO member load-serving utilities are assessed directly to SPP when SPP is an RTO (as in the Base and EIS Market cases), and then in turn assessed by SPP to member companies. Under FERC regulations, the annual FERC charge is assessed to all SPP RTO energy for load. This includes the energy transmitted to serve the load of public power companies such as municipals and cooperatives, which would not otherwise be subject to FERC charges. FERC charges for RTO members are therefore significantly higher for investor-owned utilities and are assessed for the first time to publicly owned utilities.

As more of the country's utilities join an RTO, the FERC per-unit charges for energy transmitted in interstate commerce are likely to decrease. Nevertheless, as long as only wholesale transactions are assessed the FERC charge under a non-RTO (Stand-Alone) basis, there will be higher FERC charges to RTO members than non RTO-members, all else being equal.

For purposes of this study, the impact of the FERC charges between the Base and Stand-Alone cases was estimated by comparing the FERC charges to be assessed to SPP (and then allocated to each SPP member) in 2005 to the average inflation-adjusted FERC charges paid by each individual company in the 1999–2003 period. This impact was then escalated and discounted over the 10-year study period. The 1999–2003 data were used as a source of actual FERC charges paid by SPP member companies when assessed charges on a stand-alone basis. An average over the 1999–2003 period was applied, as the charges vary by year depending on the volume of wholesale transactions. As RTOs continue to form, an increasingly larger share of FERC's total annual charges are being allocated to RTO members than the average over the 1999–2003 period. This approach therefore likely provides a conservative estimate of the savings in FERC charges that would result from stand-alone status in the future. However, it also may overestimate the savings if FERC begins to apply these charges to energy transmitted to native load by utilities that are not part of an RTO and thus puts non-RTO and RTO members on an equal footing.

Using this approach, the decrease in FERC fees under the Stand-Alone case is $47 million for the transmission owners under the SPP tariff over the study period. Since this is a reduction in costs, it is a benefit to the Stand-Alone case. Table 9 in Appendix 4-1 gives the estimated FERC charges, by company, under the Base and Stand-Alone cases.

Since the FERC charges by company would be the same in the Base and EIS cases, this cost category is not relevant to the comparison of those cases.

4.2.6 Transmission Construction Costs

Beginning in 2006, SPP will implement a new cost allocation procedure to assign costs for new transmission projects to the transmission owners under the SPP tariff. The existing cost-allocation method directly assigns the cost to the transmission owner in whose control area the project is placed in service. The new cost allocation will use a combination of direct cost assignment, MW-mile impacts, and load ratio shares to assign transmission project capital costs to individual transmission owners under the SPP tariff.

In the Stand-Alone case, the existing direct-assignment cost allocation is assumed to continue. A comparison of the new and existing cost allocation methods was therefore performed to capture the difference in new transmission project revenue requirements for individual companies under the SPP tariff. Only new transmission investment in the 2006–2010 period was considered. Since the total transmission investment is the same in both the Base and Stand-Alone cases, the aggregated impact over all transmission owners under the SPP tariff is zero.[31] For individual company impacts, see Table 10 in Appendix 4-1.

[31] While it is possible that Stand-Alone transmission investment could differ from transmission investment in the Base case, such a difference was not considered in this study. To the extent that transmission providers are

Since the new cost allocation method would be used in both the Base and EIS cases, this cost category is not relevant to the comparison of those cases.

4.2.7 Withdrawal Obligations

Moving to stand-alone status would likely require withdrawal from SPP and the payment of an exit fee or withdrawal obligation payment to SPP. The withdrawal obligation for each company was obtained from a recent (July 2004) SPP Finance Committee analysis of this issue. The withdrawal obligation payment is assumed to take place on January 1, 2006. For individual company obligations, see Table 11 in Appendix 4-1.

4.2.8 Total Benefits (Costs)

4.2.8.1 For Transmission Owners under the SPP Tariff

Table 4-1 gives the results by category for the transmission owners under the SPP tariff. The aggregate benefit is ($70.5) million over the study period, i.e., the aggregate benefits of moving to Stand-Alone status are negative. This $70.5 million figure can be thought of as the additional costs incurred by moving to Stand-Alone status.

Table 4-1 Stand-Alone Case Benefits (Costs) by Category for Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	(20.9)
Transmission Wheeling Charges	(499.8)
Transmission Wheeling Revenues	515.6
Costs to Provide SPP Functions	(46.0)
FERC Charges	27.3
Transmission Construction Costs	0.5
Withdrawal Obligations	(47.2)
Total	(70.5)

Table 4-2 gives the total impact of moving to Stand-Alone status for each transmission owner under the SPP tariff. Table 1 in Appendix 4-1 gives results by company and by category. The results in Table 4-2 are shown with and without the impact of wheeling revenues and charges. As shown, excluding wheeling impacts, the benefit of moving to Stand-Alone status for each individual transmission owner is either close to zero or somewhat negative (i.e., an increase in costs).

While the aggregate benefit for the transmission owners under the SPP tariff is negative, some individual companies show a moderately positive benefit when wheeling impacts are included. For those companies, the positive result is driven by a significant increase in wheeling revenues when through-and-out wheeling charges to other SPP companies are instituted in the Stand-Alone case. In practice, the increase in wheeling revenues would be associated with a utility that exports significant

affected by the change in cost allocation, network customers of these transmission providers are also be affected.

amounts of power to other SPP companies. Since there are no intra-SPP wheeling charges in the Base case, utilities that export significant amounts of power to other SPP companies would collect considerably more in wheeling revenue in the Stand-Alone case than in the Base case.

However, as discussed above, the change in wheeling rates in the Stand-Alone and the existence of loop flow together result in considerable uncertainty regarding wheeling impacts assessed to individual SPP companies. The collective Stand-Alone impact across SPP is a better measure than the individual company results, as the intra-SPP wheeling charges paid to/from SPP members offset one another in the collective calculation. The individual company Stand-Alone results with wheeling impacts included should therefore be viewed as representative, subject to further investigation into loop flow on individual company wheeling impacts.

Table 4-2 Stand-Alone Case Benefits (Costs) for Individual Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefits excl. Wheeling	Wheeling Impacts	Total Benefits
AEP	IOU	(19.8)	(3.0)	(22.8)
Empire	IOU	(5.8)	(19.8)	(25.6)
KCPL	IOU	(17.8)	68.7	50.9
OGE	IOU	(8.2)	(10.4)	(18.6)
SPS	IOU	(5.0)	49.5	44.5
Westar Energy	IOU	(17.0)	0.2	(16.9)
Midwest Energy	Coop	(7.9)	3.9	(3.9)
Western Farmers	Coop	1.3	(52.5)	(51.2)
SWPA	Fed	1.2	(20.9)	(19.7)
GRDA	State	(4.8)	(6.0)	(10.8)
Springfield, MO	Muni	(2.5)	6.1	3.5
Total		(86.3)	15.8	(70.5)

4.2.8.2 By State

An allocation by state was carried out for the six IOUs listed in Table 4-2. This was calculated by allocating between wholesale and retail customers using load shares and further dividing the retail customer results by state using load shares.[32] The retail customer results were further divided by state. Table 4-3 gives aggregate retail customer benefits (costs) by state for these six IOUs. Table 1-2 in Appendix 4-1 gives benefits by company by state. To the extent that agreements are in place that share costs between IOU operating companies, these considerations were not taken into account in this study.

[32] Trade benefits for AEP were allocated to the AEP operating companies, Public Service Company of Oklahoma, and Southwestern Electric Power Company prior to allocation to individual states.

Table 4-3 Stand-Alone Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

	Benefits excl. Wheeling	Total Benefits
Arkansas	(3.0)	(5.0)
Louisiana	(2.6)	(3.0)
Kansas	(22.2)	3.6
Missouri	(13.7)	2.7
New Mexico	(0.7)	5.9
Oklahoma	(16.2)	(25.9)
Texas	(5.5)	16.4

4.2.8.3 Other Results

Using the methodology described above, the benefit for other typical members that pay an SPP assessment (Arkansas Electric Cooperative Corporation; The Board of Public Utilities, Kansas City, Kansas; Oklahoma Municipal Power Authority; City of Independence, Missouri) is also computed and included in Table 1 in Appendix 4-1. The additional cost of moving to stand-alone status for these four typical members is $4.7 million. The additional cost incurred by SPP merchants when SPP transmission owners under the SPP tariff move to stand-alone status is $8.6 million.

Table 1 in Appendix 4-1 also lists the benefits to other load-serving utilities that are members of SPP but are not transmission owners under the SPP tariff. Considering only trade benefits and wheeling impacts, these utilities incur additional costs of $9.3 million when SPP transmission owners under the SPP tariff move to stand-alone status.

Finally, the rest of the Eastern Interconnect,[33] again considering only trade benefits and wheeling impacts, incurs additional costs of $30.5 million when SPP transmission owners under the SPP tariff move to stand-alone status. As shown in Appendix 4-1, Table 1, the total trade benefits and wheeling impacts across all companies is an additional cost of $53.8 million. As discussed above, this is exactly equal to the increase in production costs across the modeled footprint from the Base to the Stand-Alone case.

4.3 EIS Market Case Results and Discussion

4.3.1 Trade Benefits

Implementation of the EIS Market leads to a more efficient dispatch and thereby yields system-wide production cost savings in comparison to the Base case. Production costs savings for the entire Eastern Interconnect are $1,173 million over the study period. Production cost savings for the

[33] In the CBA the "Eastern Interconnect" includes the majority of the Eastern Interconnect, but excludes—for example—the Northeast markets.

transmission owners under the SPP Tariff are $2,569 million, while, in contrast, SPP merchants have a production cost increase of $2,670 million. As discussed above, these production cost impacts are shared among individual companies through trading. Using the methodology outlined above, the trade benefits for the transmission owners under the SPP Tariff in the EIS Market case are $614 million. Thus, transmission owners under the SPP tariff obtain 52% ($614/$1173) of the total trade benefits.

Tables 3, 4 and 5 in Appendix 4-2 give annual trading benefit results, production cost changes, and generation changes by company over the study period.

4.3.2 Transmission Wheeling Charges

No changes to wheeling rates from the Base case are assumed to take place in the EIS case. However, implementation of the EIS Market does change generation levels and tie-line flows. As noted above, the native load in each control area is assumed to pay the wheeling charges associated with the import of power. The wheeling charges decrease by $24 million over the study period for the transmission owners under the SPP Tariff. Since these are payments, this is a positive benefit to the EIS case. Table 6 in Appendix 4-2 gives annual wheeling charge increases by company over the study period.

4.3.3 Transmission Wheeling Revenues

Similarly, implementation of the EIS market changes also affects wheeling revenues. The wheeling revenues are paid to the exporting control area's transmission provider, and then allocated to the native load in that control area. That is, wheeling revenues are used to reduce the transmission revenue requirement for native load. The wheeling revenues for the transmission owners under the SPP Tariff decrease by $54 million. Since these are revenues, this is a negative benefit to the EIS case. Table 7 in Appendix 4-2 gives annual wheeling revenue increases by company over the study period. Since wheeling rates are unchanged between the Base and EIS market cases, the individual company wheeling impacts for the EIS market case are less affected by loop flow issues than those in the Stand-Alone case. With no change in wheeling rates and no intra-SPP wheeling rates, the loop flows will not significantly impact the change in wheeling impacts between the Base and EIS market cases if the loop flows into and out of SPP are similar in both cases.

4.3.4 SPP EIS Implementation and Operation Costs

SPP will incur considerable expenditures in implementing and operating the EIS market. These expenditures, in turn, will be assessed to the EIS market participants. An evaluation of the SPP budget was performed to project the costs that would be assessed to individual EIS market participants. For the transmission owners under the SPP tariff, the total cost that will be passed through by SPP is $104 million over the study period. Since this is an additional cost, this is a negative benefit to the EIS case. Table 8 in Appendix 4-2 gives the annual costs that would be assessed to EIS market participants.

4.3.5 Participant EIS Implementation and Operation Costs

EIS market participants will incur significant expenditures to participate in the EIS market over and above SPP's assessments for its own expenditures. In response to a request by CRA, EIS market participants provided a detailed annual estimate of the additional labor, O&M, and capital costs they would incur over the study period to participate in the EIS market. Appendix 4-4 gives details on these cost estimates. These costs were converted to annual revenue requirements and are summarized in Table 9 in Appendix 4-2. The total cost to transmission owners under the SPP tariff over the study period is $107 million. Since this is an additional cost, this is a negative benefit to the EIS case.

4.3.6 Total Benefits (Costs)

4.3.6.1 For Transmission Owners under the SPP Tariff

Table 4-4 shows the results by category in aggregate for the transmission owners under the SPP tariff. The aggregate benefit is $373.1 million over the study period.

Table 4-4 EIS Market Case Benefits (Costs) by Category for Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	614.3
Transmission Wheeling Charges	24.4
Transmission Wheeling Revenues	(53.2)
SPP EIS Implementation Costs	(104.8)
Participant EIS Implementation Costs	(107.6)
Total	373.1

For each individual transmission owner under the SPP tariff, the total impact of moving to an EIS market is shown in Table 4-5. Table 1 in Appendix 4-2 gives results by company by category. While the aggregate benefit is positive, some companies show net additional costs. For those companies, the additional cost is driven by a relatively limited change in generation dispatch under an EIS market, which limits the accrual of trade benefits under the allocation method used in this study.

Table 4-5 EIS Market Case Benefits (Costs) for Individual Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefit
AEP	IOU	58.5
Empire	IOU	70.0
KCPL	IOU	(2.2)
OGE	IOU	95.3
SPS	IOU	69.4
Westar Energy	IOU	5.3
Midwest Energy	Coop	(0.7)
Western Farmers	Coop	75.2
SWPA	Fed	1.2
GRDA	State	(5.0)
Springfield, MO	Muni	6.0
Total		373.1

4.3.6.2 By State

An allocation by state was performed for the six investor-owned utilities listed in Table 4-5 above. As noted above, this was calculated by allocating between wholesale and retail customers using load shares and further dividing the retail customer results by state using load shares. [34] Table 4-6 shows aggregate retail customer benefits (costs) by state for these six investor-owned utilities. Table 2 in Appendix 4-2 gives benefits by individual investor-owned utility by state. Again, to the extent that agreements are in place that share costs between IOU operating companies, these considerations were not taken into account in this study.

Table 4-6 EIS Market Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Arkansas	9.2
Louisiana	(3.8)
Kansas	8.3
Missouri	60.0
New Mexico	9.2
Oklahoma	141.7
Texas	26.6

4.3.6.3 Other Results

Using the methodology described above, the benefit for other typical members that pay an SPP assessment (Arkansas Electric Cooperative Corporation; The Board of Public Utilities, Kansas City, Kansas; Oklahoma Municipal Power Authority; City of Independence, Missouri) is also computed and included in Table 1 in Appendix 4-2. The collective benefit for these four typical members is $45.2 million without consideration of individual implementation costs, and this figure represents almost all of the remaining regulated generation for SPP members paying an SPP assessment.

The benefits to SPP merchants when the transmission owners under the SPP tariff form an EIS market are $123.9 million. The generation of the merchant plants is substantially greater in the EIS market case, and, as discussed above, merchants are attributed 50 percent of the trade benefits that accrue from their participation in the EIS market, with native load receiving the other 50 percent through contractual arrangements.

Table 1 of Appendix 4-2 gives the benefits to other load-serving utilities that are members of SPP but are not transmission owners under the SPP tariff and do not pay an annual assessment to SPP. These entities are not part of the EIS as currently formulated, but will nonetheless be affected by the institution of the EIS. Only trade benefits and wheeling impacts were evaluated for these utilities, which have a collective benefit of $28.6 million.

[34] Trade benefits for AEP were allocated to the AEP operating companies, Public Service Company of Oklahoma, and Southwestern Electric Power Company prior to allocation to individual states.

The balance of the Eastern Interconnect has a collective benefit of $382.6 million, again considering only trade benefits and wheeling impacts. Table 1 in Appendix 4-2 indicates that the total impact of trade benefits and wheeling impacts across all companies is $1,173 million. As discussed above, this is exactly equal to the decrease in production costs across the modeled footprint from the Base case to the EIS case.

5 Qualitative analysis of Energy Imbalance Market Impacts

This section explores impacts of SPP's implementing an Energy Imbalance Service (EIS) other than those impacts captured elsewhere in this report. (Section 3 addresses the potential energy market impacts that were determined quantitatively; Section 4 addresses expected SPP and market participant costs as part of the allocation.)

This assessment was made by comparing the existing imbalance energy provisions contained in SPP's Open Access Transmission Tariff with the filed tariff provisions and draft protocols describing the Imbalance Energy (IE) market. The following reference documents were relied upon:

Existing Settlement Provisions:

- Open Access Transmission Tariff (OATT) for Service Offered by the Southwest Power Pool, November 1, 2000
- Revised, SPP Board Approved, OATT Section 3 and Schedule 4-A
- Transmission Owner Tariff provisions for Imbalance Energy Settlement, as summarized by SPP staff, November 2004

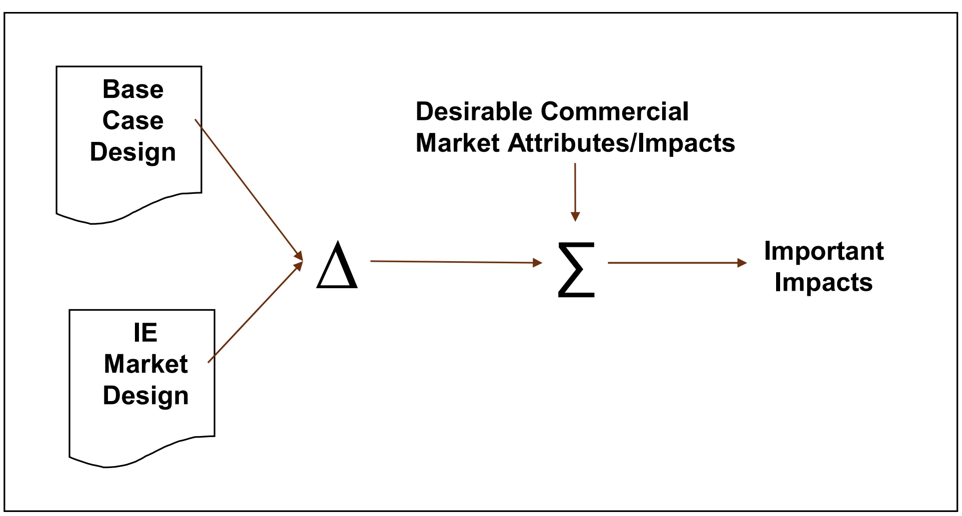
Future-State (EIS) Market Provisions:

- SPP Market Protocols (Draft) v2, January 6, 2005
- RTO Proposal of Southwest Power Pool, Inc., Volume I, October 25, 2003
- Market Working Group Meeting materials - various

5.1 Methodology

Figure 5-1 shows the general approach to assessing qualitative impacts associated with the EIS.

Figure 5-1 EIS Qualitative Assessment Methodology



Generally the existing and proposed EIS market designs were compared to identify significant design changes and underlying drivers of those changes. After a preliminary consideration of the potential impacts of the Significant Design Changes on SPP and the market participants, CRA grouped the potential impacts into nine categories of C*ommercial Impacts*, which are listed and briefly described in Table 5-1.

The subsections that follow present the significant design changes and underlying drivers, followed by the Commercial impacts.

Table 5-1 Commercial Impacts

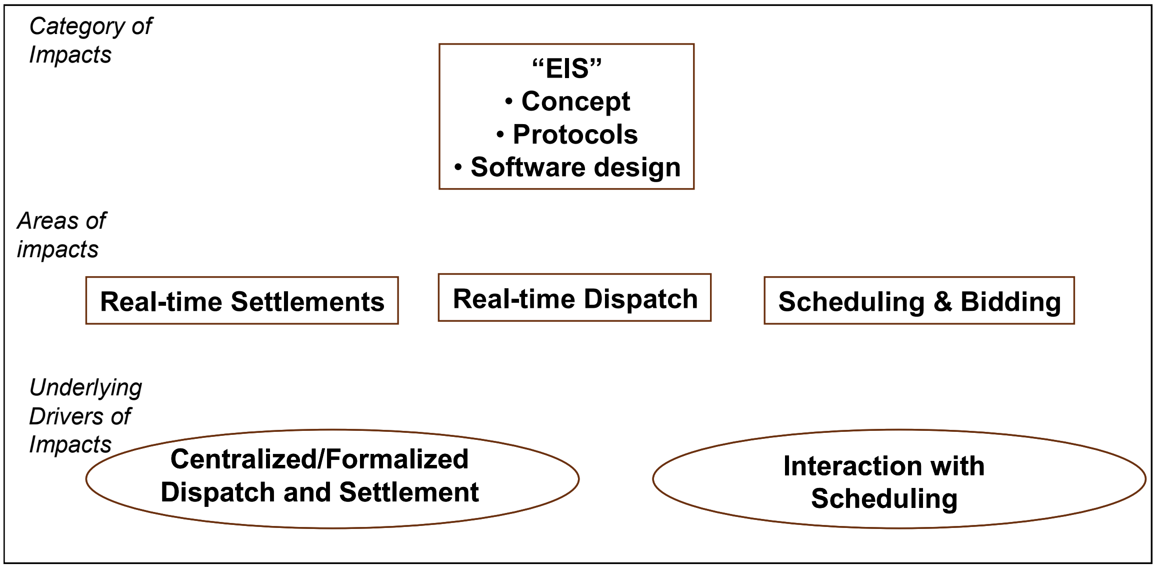
Commercial Impact	Illustrative Description
1. [Facilitate Development of] **Competitive Markets**	Does the Significant Design Change facilitate or hinder competition or market penetration (the ability of new retailers to compete for load)—for example, through complexity, volatility or cost shifting?
2. [Minimize] **Discriminatory Environment**	Does the Significant Design Change reduce perceived or actual barriers that unduly discriminate against small/large players, non-incumbents, etc.?
3. [Increase] **Efficiency of Production**	Does the Significant Design Change encourage the efficient use (dispatch, commitment) of existing facilities and/or promote economic efficiency in the consumption of electricity? (This considers microeconomic principles and also incorporates maximization of social welfare—the sum of consumer and producer surplus.)[35]
4. [Promote] **Efficient Resource Expansion**	Does the Significant Design Change provide proper incentives for resource investment (including Distributed Generation and Demand-Side Management)? This includes the need for site-specific pricing and resource siting signals, and changes in risk and/or uncertainty associated with nodal pricing.
5. [Promote] **Efficient Grid Expansion**	Does the Significant Design Change encourage or discourage investment in the grid by various entities? At the right locations? With the proper trade-offs between wires and resources/Demand Side Management?
6. [Neutralize] **Opportunities to Exercise Market Power**	Does the Significant Design Change increase or decrease the need for mechanisms to mitigate potential abuse of market power?
7. [Enhance] **Grid Reliability**	Does the Significant Design Change recognize the physical realities of the grid, reduce burdens on grid operators, and reduce the potential for (uneconomic) loss of load?
8. [Facilitate] **Ability to Conduct Business**	Does the Significant Design Change make it easier for entities to participate in the SPP market?
9. [Minimize] **Costs and Administrative Burdens**	Does the Significant Design Change reduce or increase costs (that are not already accounted for in the IIA) and burdens on market participants and on SPP?

[35] Note that this metric, as described, reflects Social Welfare generally. However, various impacts tend to affect producer surplus or consumer surplus. Given that which of these may be impacted may be relevant to various stakeholders (and it is not the consultant's role to judge the merits of how the social welfare is experienced), the discussions within the text identify, where possible, how the efficiency gains are expected to be experienced (for example, when Load Serving Entities are better off).

5.2 Market Rule Changes

While the EIS primarily relates to the settlement of imbalance energy, instituting a formal locational balancing energy has additional impacts. These impacts can be viewed on several levels, as shown in Figure 5-2.

Figure 5-2 EIS Changes - Various Views



There are several areas of impacts, and these have some common underlying drivers. The impact areas considered can be summarized as follows:

Real-time market: Impacts of Settlement using Locational Imbalance Pricing (LIP)

The most direct and obvious impacts related to instituting a formal Imbalance Energy market with locational pricing are associated with the changed settlement rules and processes; they include the impacts on loads and on generators of the change in pricing and settlement processes. For example, with the EIS:

- SPP manages, in a centralized way, settlements for inadvertent energy that were previously conducted bilaterally with each Control Area Operator (CAO).
- CAOs settle imbalance energy for load formally with SPP rather than simply load following or settling with neighboring control areas.
- Pricing between supply sources may be different than pricing of load.
- New metering reporting and management requirements are created.

While the fundamental impacts of the pricing changes are addressed in the MAPS modeling aspect of this study, and the infrastructure costs are addressed specifically, the movement to a formal EIS creates other non-monetized impacts.

Real-time: SPP Real-time Resource Deployment

In addition to the financial implications of LIP energy settlement, the EIS design includes the centralized optimization and dispatch of balancing energy sources. This creates the need for specific infrastructure from SPP, and likely for members, and it may substantially change the operational management of generator units in real-time. Each CAO no longer optimizes and deploys resources to balance its own system; instead, generation operators submit bid curves to SPP, which optimizes the balancing energy resources using a Security-Constrained Economic Dispatch (SCED) algorithm and (for units providing balancing energy) determines which units generate to what levels in real-time—providing formal dispatch notices.

Forward Market Impacts: Schedules and Bid Impacts

Given that the EIS creates the need for formal communication of system conditions and of individual participants' expected behavior and input data, the implementation of the EIS creates additional forward scheduling requirements. To operate an EIS, SPP needs specific and timely resource plan information. SPP will use a baseline of forward load and generation schedules as an allocation basis over which to allocate the financial results of the EIS market. Thus, the EIS creates different forward market requirements and may have different settlement impacts related to activities in the forward market. Application of uninstructed deviation charges or penalties to scheduled-to-real time difference and the use of the EIS to manage Firm schedules are examples of these types of impact. In some cases, these impacts are more significant during the period when there will be a locational market-based real-time congestion management system, but no forward congestion management system.[36]

5.3 Underlying Drivers

There appear to be two underlying drivers for the areas of impact just described, and these are essentially operational in nature:

1. Centralized/formal control of real-time balancing

   This driver relates to both operational control and pricing control and seems to be the strongest.

2. Relationship of real-time EIS coupled with scheduling

   The ultimate impacts are considered in the sense of these two underlying drivers.

5.4 Impacts of Underlying Drivers

This discussion presents those commercial impacts resulting from the fundamental drivers.

[36] For example, the issue of overscheduling or under-scheduling counterflow likely falls into this category in the sense that if SPP had a comparably-based congestion management system in the Day Ahead there would be more naturally balancing incentives for scheduling.

Facilitation of Competitive Markets

The long-run impacts of implementing a formal nodal EIS are expected to include improved transparency and improved price signals, and experience in other markets suggests that these will be the predominant impacts. Complexity produces adverse impacts during a transition period—for example, when parties are affected by locational balancing EIS prices yet do not have the operating history of what these prices and respective points' price spreads might be. Such impacts are expected to be alleviated with operating stability and history. That is, the market will eventually establish a pricing history that will provide market participants data reflecting expected pricing risks.

Applying explicit imbalance energy prices creates risks associated with not following schedules. The relative impact depends on the details of what is in place today regarding imbalance energy settlement with the CAOs. Whether the implementation of any test for schedule feasibility[37] when used in isolation without a formal day-ahead or hour-ahead congestion management market, will enhance or impede the competitiveness of the market depends on the effectiveness of the particular mechanisms implemented. Similarly, to the extent that the new centralized LMP algorithms or SCADA systems do not work correctly, there will be adverse impacts on the market until those issues are resolved.[38]

Market monitoring provisions offer the potential for more competitive markets, provided that they are not overly burdensome and that they do not create undue regulatory risk.

Minimize Potential Discriminatory Behavior

The movement to an explicit EIS should increase transparency, which would reduce the potential for discriminatory behavior and improve the competitiveness of markets generally.

Efficiency of Production

The production efficiency impacts of the EIS are measured by the MAPS modeling. To the extent that the EIS is cleared as efficiently as the model assumes, the numerical modeling results are expected to reflect the EIS benefits. To the extent that bilateral schedules do not directly reflect the efficient dispatch, and to the extent that the EIS is not used to manage congestion for the bilateral schedules, the predicted benefits may not be realized.

The movement with the EIS to the centralized management of inadvertent energy will likely have added production efficiencies that are not captured in the quantitative results of the MAPS modeling.[39]

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[37] Note that some of the market design documents have contemplated the possibility that a "feasibility" test for schedules may be necessary to implement a workable real-time EIS. How "feasibility" will be determined, however has not yet been specified.

[38] That SPP intends to have policies related to the quality control and improvement of the EIS algorithms and SCADA systems is seen as a positive indication that any adverse software impacts will be minimized.

[39] The MAPS modeling assumes in all cases that inadvertent energy management is perfectly efficient at the seams of SPP, other than the financial effect of the boundary wheeling rates.

Resource Expansion

Location-specific and transparent pricing at nodes should provide improved price signals for siting. In other markets that CRA has observed, however, institutional barriers have emerged that prevented the market from responding appropriately to such price signals. These barriers include exogenous factors (e.g., NIMBY) that continue to have strong influences, and other market structures—such as capacity market implementation—that may dampen the price signals that are needed to overcome other factors. While specific nodal price signals should be beneficial, realizing their full benefit may take time while such other market structures are modified.

Grid Expansion

The implementation of the EIS is not likely to significantly improve grid planning or expansion. This is because long-term transmission investments must be justified primarily on the basis of anticipated future demand and long-term projections of future costs, rather than on specific historical uses and congestion costs. Most planners already use nodal information to determine the most appropriate transmission upgrades, so that the EIS nodal pricing for balancing energy seems to provide no direct advantage or disadvantage in the area of grid expansion.

Market Power

This study did not include an assessment of the propensity for any participant to exercise market power. One might expect that the EIS would reduce the ability to exercise vertical market power, given that SPP will be operating the EIS market. Participants may fear, however, that the ability to exercise horizontal market power might be greater, or perhaps more specifically that the consequence of the exercise of horizontal market power might be higher given that marginal pricing—as opposed to average pricing or returning "in-kind" energy for example—may have large pricing impacts in the EIS. While these factors are at play, it is not possible to determine whether the resulting impact, combined with the impacts of a market monitoring plan, would be positive or negative overall.

Grid Reliability

The grid is operated reliably today and it will be operated reliably under an EIS. This issue therefore addresses whether there are any factors that provide marginal additional levels of reliability. Here again balancing factors are likely at play. The movement to an SPP centralized real-time dispatch and balancing should afford more visibility and a broader perspective than does individual control area operations. This is a plus. At the same time, however, movement away from CAO balancing creates the possibility that specific knowledge of local grid issues will be lost over time. This loss of expertise is a disadvantage of the EIS in the sense of margins of reliability. Further, the EIS may result in exercise of the generation system in manners not previously experienced[40] and the centralized dispatch of resources may result in more rapid movements that require more regulation control. To the extent that this effect is strong, the reliability margin may be somewhat reduced.

It is not clear that either of these offsetting effects is significantly stronger than the other.

[40] For example, with the fluid participation of independent generator resources in the EIS, the dispatch of the system will change; in addition, CAOs' regulation units will no longer be operated in conjunction with the CAO-controlled deployment of balancing energy resources.

Ability to Conduct Business and Administrative Burdens

This study quantitatively captures the costs to participate in the EIS. Both costs to SPP and costs to market participants are estimated. However, it is possible that these costs—especially those born by market participants—are not captured consistently across all market participants. Costs that may be outside the quantified values may include, for example, costs of increased scheduling needs, utilities' costs of hedging new EIS risks, and the costs of regulation unit owners associated with the price risk of regulation energy (the energy provided by the regulating units in real-time in response to frequency-control signals) relative to EIS energy. Similarly, parties that have in the past settled real-time imbalances with one more control areas will be relieved of the administrative costs of performing those settlements. It is not clear whether such costs were included in the quantifications of EIS costs.

5.5 EIS Qualitative Analysis Summary

Overall, it is expected that implementation of the EIS will create additional transparency and efficiency benefits. However the EIS will also increase administrative burdens, though it is likely that a significant fraction of these additional burdens will be transitional, meaning that they will return more or less to today's level once the EIS has been in place for some time (roughly 1 to 3 years). Further, it is likely that the administrative and infrastructure costs borne by participants for the EIS will be "lumpy," in the sense that allowing for the EIS requires significant infrastructure much of which will be useable also for the full day-ahead market and congestion management process if, and when, it is implemented.

6 Qualitative Analysis of Market Power Impacts

The SPP Regional State Committee has asked CRA to address market power issues that might arise in the context of the implementation of the EIS market, in particular. The question is whether the EIS market would provide an increased opportunity to exercise market power on the part of one or more owners of generation resources in the area. In this context, it is useful to recall that market power is the ability and incentive to increase market prices by a significant amount for an extended period. In particular, a generation owner must have both the ability and the incentive to exercise market power in order to be considered as possessing market power at all, regardless of whether it actually exercises that market power.

6.1 Market Monitoring

Market monitoring and mitigation is an essential function for RTOs and is required by FERC Order 2000. As part of the institution of an EIS market, SPP will implement a market monitoring process that includes the appointment of an independent contractor to oversee the safe and reliable operation of SPP's transmission system.

The principal functions of SPP's market monitoring process are the following: reporting on compliance and market power issues relating to transmission services, including compliance and market power issues involving congestion management and ancillary services; evaluation and recommendations respecting any required OATT revisions, standards or criteria; ensuring that market monitoring is performed in an independent manner; developing procedures to inform government agencies and others with respect to market activities; monitoring market behavior and market participants to determine whether any activity is constraining transmission or excluding competitors; and ensuring the non-discriminatory provision of transmission service by SPP.

SPP has proposed a Market Monitoring Plan intended to provide for the monitoring of SPP's market and for the mitigation of the potential exercise of horizontal and vertical market power by market participants. The plan will be implemented and maintained by two Market Monitors: a Market Monitoring Unit (MMU) internal to SPP, and an Independent Market Monitor (IMM).

The MMU has primary responsibility for implementing the Plan, with the advice and oversight of the IMM, by (a) continuously monitoring SPP's markets and services provided under SPP's OATT, (b) implementing approved market mitigation measures, (c) taking the lead in investigations and in compliance and corrective actions, and (d) collecting and retaining relevant data and information.

The IMM has several responsibilities. Among these, the IMM: (a) develops, reviews, and recommends updates to the monitoring and mitigation procedures and supports SPP in obtaining FERC approval for such procedures, (b) suggests revisions to the SPP market design and procedures, (c) advises the MMU and monitors its activities, (d) advises the SPP Board, and (e) periodically reports on SPP's market and services.[41]

Together, the SPP MMU and the IMM will monitor SPP's markets and services by analyzing market data and information such as the following: resource and ancillary service plans, schedules and offer curves submitted for generating units; commitment and dispatch of generating units; locational

[41] SPP Market Monitoring Plan, OATT Attachment, Draft 11/8/04

imbalance prices; control area data (e.g., net scheduled interchange, actual net interchange, and forecasts of operating reserves and peak demand); transmission services and rights (e.g., ATC, AFC, tariff administration, operation and maintenance of the transmission system, markets for transmission rights, and reservation and scheduling of transmission service); transmission congestion; and settlement data.[42]

Market participants or government agencies may submit confidential complaints or requests for investigation to the MMU or the IMM. The MMU and/or the IMM may engage in discussions to resolve issues informally, may issue demand letters requesting market participants to discontinue actions as necessary to achieve mitigation and/or compliance, and may implement any FERC-approved mitigation measure. A process is also in place for the MMU or the IMM to recommend changes in market design or procedures as needed to ensure just and reasonable prices. The IMM will publish annual state-of-the-market reports and quarterly reports on instances of market power, if any. The IMM will also provide an annual review of the activities of the MMU.[43]

SPP estimates that market monitoring will cost about $1 million per year, or about $0.005 per megawatt-hour of net annual energy for the SPP region.

6.2 Generation Market Power

CRA has not conducted a formal, quantitative review of the potential impact of the SPP Energy Imbalance Market on the likelihood that market power might be exercised in the generation market within SPP. Such an assessment would be hypothetical and difficult to quantify given the uncertainty concerning future economic conditions and future market behavior of participants.

In CRA's view, the implementation of the Energy Imbalance Market, by itself, is unlikely to increase significantly the likelihood of actual exercises of market power in the SPP generation market. This is because most power delivered within SPP will be subject to the continuation of cost-based retail rates. In addition, it is our understanding that much of the wholesale market is covered by long-term contracts for which a short-term increase in the spot price for power would be immaterial. In these circumstances, generation owners in SPP would have little, if any, incentive to withhold generation from the SPP Energy Imbalance Market for the purpose of increasing the market-clearing price in that market. This is because the output of the generating unit is committed to load under regulatory and contractual arrangements under which it is not possible to earn additional revenue merely because of an increase in the spot market price. Without the incentive to exercise market power, which would be lacking under cost-based regulation and long-term contracts, the issue of market power is likely to be a minor consideration under the SPP market conditions.

Nonetheless, it is important that the SPP Market Monitoring Unit and the SPP Independent Market Monitor review the performance of the SPP Energy Imbalance Market and report their findings to FERC as needed. The market monitoring function is an important deterrent to the exercise of whatever residual market power exists in the market.

Given the underlying economic fundamentals of regulation and long-term contracting in the SPP area, and SPP's plans for active and ongoing monitoring of the market, CRA believes that the potential for the exercise of market power in the SPP Energy Imbalance Market is not likely to be significant and

[42] Ibid.
[43] Ibid.

should not be considered a significant risk in the implementation of that market. We have not reviewed the costs versus the reduced-risks/benefits of the market monitoring function itself given that this function is required under current FERC guidelines in any case.

7 Aquila Sensitivity Cases

7.1 Aquila Sensitivity Cases—Methodology

The Aquila Sensitivity cases measured the wholesale energy modeling impact of Aquila being a part of SPP rather than of the MISO RTO during the simulation year 2006. In the balance of the study's wholesale energy modeling, Aquila was assumed to be part of MISO. The Base and EIS cases were simulated.

Aquila consists of two control areas, which in the study are designated as Missouri Public Service (MIPU) and WestPlains Energy (WEPL). To simulate the configuration of SPP with Aquila as a member, the following changes were made to the cases:

- **Wheeling rates.** Wheeling rates between Aquila and other SPP areas were eliminated, while wheeling rates were instituted between Aquila areas and MISO.
- **Reserves.** Because of the formula used to calculate reserve requirements in SPP (largest contingency plus one-half the next largest contingency) the total reserve requirements for SPP do not change between the two cases. With Aquila as a member, however, this requirement is spread over a greater load base, so the reserve requirement for each individual member company is reduced. Because MISO reserves are met on a system-wide basis as a percent of load, the total reserve requirement in MISO is also reduced if Aquila becomes part of SPP. (Though the average load share of reserves in MISO would remain the same.)
- **Commitment.** In the Aquila sensitivity case, units in WEPL and MIPU are committed against load in SPP.

Wholesale energy results were generated for the Aquila case for both the Base and EIS cases. No specific analysis of cost or benefit allocation (such as the allocations described in Section 4) was performed for the Aquila cases.

7.2 Aquila Sensitivity Cases—Results

This section presents the results of the Aquila sensitivity runs. Results are presented such that readers can both compare the impacts for either case (Base or EIS) of Aquila being part of MISO or of SPP, and also see the extent to which the benefits of the EIS case are sensitive to Aquila being in MISO or SPP.

Table 7-1 shows results for the combined SPP and Aquila footprint[44] for four fundamental physical and financial metrics:

- Generation
- Average per MWh generation cost
- Total generation cost, normalized to the generation levels of the Aquila in MISO, Base case
- Average regional spot price of energy

[44] For a consistent comparison, the results are shown inclusive of Aquila regardless of whether Aquila is in SPP or MISO.

Table 7-1 SPP and Aquila Regional Results

	Base Case			EIS Case			EIS - Base		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
Generation in SPP + Aquila (GWh)	204,865	206,637	(1,772)	207,406	209,422	(2,016)	2,541	2,785	(244)
Average Generation Cost ($/MWh)	$ 19.07	$ 19.12	$ (0.05)	$ 18.68	$ 18.74	$ (0.06)	$ (0.39)	$ (0.38)	$ (0.01)
Normalized Generation Costs ($million)	$ 3,907	3,917	$ (10)	$ 3,827	3,839	$ (12)	$ (80)	$ (78)	$ (2)
Per MWh Spot Energy Cost	$ 40.59	$ 40.75	$ (0.16)	$ 38.10	$ 38.35	$ (0.26)	$ (2.49)	$ (2.40)	$ (0.09)

The simulations indicate that the region generates more if Aquila is located with SPP than it does if it is located within MISO under both the Base and EIS cases. Regional generation costs are simulated to be $10 million to $12 million lower if Aquila is in MISO, roughly 0.25% of the region's total generation cost. Spot marginal energy costs are expected to be $0.16/MWh less expensive with Aquila in MISO under the Base case and $0.26/MWh less expensive under the EIS case.

The column entitled EIS-Base, Difference (MISO-SPP) indicates, as shown by the relatively small values for each metric, the benefits of the EIS market for the region as measured in the modeling is not particularly sensitive to whether Aquila is in MISO or SPP.

Table 7-2 shows the impact similar to Table 7-1 on the Aquila companies only.

Table 7-2 Aquila Companies' Results

	Base Case			EIS Case			EIS - Base		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
Generation Aquila (GWh)	6347	6295	52	6280	6307	(27)	(67)	12	(79)
Average Generation Cost Aquila ($/MWh)	$ 21.07	$ 20.80	$ 0.27	$ 20.79	$ 20.71	$ 0.08	$ (0.28)	$ (0.09)	$ (0.19)
Normalized Generation Costs Aquila ($million)	$ 133.72	$131.99	$ 1.73	$ 131.94	$131.43	$ 0.50	$ (1.79)	$ (0.56)	$ (1.22)

Table 7-2 indicates several characteristics of the Aquila impacts as given by the modeling:

- Aquila companies generate more if in MISO under the Base case, but more if in SPP if SPP has an Energy Imbalance market. (In both cases the change in Aquila generation is less than 1%).
- Based on generating costs, Aquila shows benefits of being a member of SPP, and those benefits are higher under the Base case than under the EIS case (1.3% and 0.3%, respectively)

Also notable from the information shown in Tables 7-1 and 7-2 is that while the SPP region's generating costs would be lower with Aquila in MISO ($10 million in the Base case), Aquila's generating costs would be lower with Aquila in SPP ($1.7 million in the Base case).

Table 7-3 shows the impact on NOx and SOx emissions. As with the generation costs, the impacts to the Aquila emissions behave opposite to that of the SPP region to whether Aquila is in SPP or MISO, and in this sense the impacts on emissions between Aquila and SPP are somewhat offsetting. In either case the impact to SPP or to Aquila is approximately a 1% change in emissions.

Both Aquila companies show benefits from being in SPP. Under both the Base and EIS cases, the generator net revenues for MIPU are higher if Aquila is in SPP ($2 million for the Base case, $2.7 million for the EIS case), but the load energy costs are lower if MIPU is in SPP ($2.6 million for the Base case, $2.2 million for the EIS case).

For WEPL, the magnitude of the increase in generation net revenues when WEPL is part of SPP is lower than it is for MIPU ($0.8 million for the Base case, $1.4 million for the EIS case). The impact to load is comparable, a saving if part of SPP of $2.4 million in the Base case, $2 million in the EIS case. Note that the energy cost impact for WEPL is a savings of approximately $1/MWh if Aquila is in SPP. This relatively significant savings is due to the fact that WEPL is entirely within the SPP footprint (as opposed to MIPU, which borders to some extent MISO).

Table 7-3 Emission Impacts of Aquila Cases

	Base Case			EIS Case			EIS - Base		
	NOx Emissions (Tons)			NOx Emissions (Tons)			NOx Emissions (Tons)		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
SPP	283,538	286,624	(3,086)	276,929	279,640	(2,711)	(6,608)	(6,984)	376
Aquila Companies	18,477	18,297	180	18,243	18,296	(52)	(233)	(1)	(232)
Total SPP+ Aquila	302,014	304,920	(2,906)	295,173	297,935	(2,763)	(6,842)	(6,985)	143

	Base Case			EIS Case			EIS - Base		
	SOx Emissions (Tons)			SOx Emissions (Tons)			SOx Emissions (Tons)		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
SPP	449,349	454,883	(5,535)	449,010	453,982	(4,971)	(338)	(902)	563
Aquila Companies	22,173	22,102	71	22,049	22,144	(95)	(124)	43	(166)
Total SPP+ Aquila	471,521	476,985	(5,464)	471,059	476,126	(5,067)	(462)	(859)	397